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ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1987

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DECISIONS

ISSUED IN 1987

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
D 87-1	861300	APPLICATION TO CONSTRUCT A PIPELINE AND RELATED FACILITIES NOVACORP PIPELINES LTD.	5 JANUARY 1986
D 87-1 Addendum	861300		
D 87-2	861401	APPLICATION FOR A WELL LICENCE ACHESON EAST FIELD TUMIT PETROLEUMS LTD.	6 JANUARY 1987
D 87-3	861141	APPLICATION FOR A WELL LICENCE PEMBINA FIELD DIAMOND SHAMROCK EXPLORATION	22 JANUARY 1987
D 87-4	861614	APPLICATION FOR A WELL LICENCE WEST DRUMHELLER AREA COREXCAL, INC.	10 JANUARY 1987
D 87-5	860673	REDUCED GAS WELL SPACING PREVO FIELD G.N.E. RESOURCES LTD.	18 FEBRUARY 1987
D 87-6	850272	INCREASED THROUGHPUT AND ETHANE RECOVERY WAPITI GAS PROCESSING PLANT SULPETRO LIMITED	27 MARCH 1987
D 87-7	860891, 870055, 870061	GAS CYCLING APPLICATIONS BRAZEAU RIVER NISKU P POOL DOME PETROLEUM LIMITED PETRO-CANADA INC. AMOCO CANADA PETROLEUM COMPANY LTD.	4 MARCH 1987
D 87-8	861525, 870045, 870046, 870047	APPLICATIONS FOR APPROVAL OF THE TRANSPORTATION AND PROCESSING OF HIGH HYDROGEN SULPHIDE SOUR GAS RESERVES IN THE CAROLINE FIELD AND AREA (BEARBERRY DEMONSTRATION PROJECT) SHELL CANADA LIMITED	7 APRIL 1987
D 87-9	861041	APPLICATION FOR APPROVAL OF A GAS PROCESSING PLANT IN THE CAMPBELL-NAMAO FIELD NORCEN ENERGY RESOURCES LIMITED	16 APRIL 1987
D 87-10	861314	AMENDMENT TO BOARD APPROVAL NO. 5147 ENHANCED RECOVERY-MITSUE GILWOOD A POOL CHEVRON CANADA RESOURCES LIMITED	12 MAY 1987

DECISIONS

ISSUED IN 1987

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
D 87-11	870817	APPLICATION FOR A WELL LICENCE MEDICINE HAT FIELD PANCANADIAN PETROLEUM LIMITED	30 JULY 1987
D 87-12	870639	240-KV TRANSMISSION LINE RE-ROUTE STAR AREA ALBERTA POWER LIMITED	11 JUNE 1987
D 87-13	870677	APPLICATION TO CONSTRUCT A PIPELINE AND RELATED FACILITIES - BONNIE GLEN TO ACHESON	6 AUGUST 1987
D 87-13 Addendum	870677	FEDERATED PIPE LINES LTD.	
D 87-14	870308	ALBERTA-SASKATCHEWAN INTERCONNECTION EMPRESS AREA	10 SEPTEMBER 1987
D 87-14 Addendum	870308	ALBERTA POWER LIMITED	
D 87-15	870791	PIPELINE CONSTRUCTION AT ROAD CROSSINGS - COUNTY OF LAC STE. ANNE PEACE PIPE LINE LTD.	18 SEPTEMBER 1987
D 87-16	870417 AND 870418	WELL LICENCE APPLICATIONS WATERTON/PRAIRIE BLUFF AREA SHELL CANADA LIMITED	25 SEPTEMBER 1987
D 87-17	871017 AND 871018	APPLICATIONS FOR PERMITS TO CONSTRUCT PIPELINES TO TRANSPORT SOUR GAS AND FUEL GAS IN THE CAROLINE AREA GULF CANADA CORPORATION	27 NOVEMBER 1987
D 87-18	860247, 860248, 860249	SPECIAL GAS WELL SPACING FERRYBANK AREA UNION PACIFIC RESOURCES INC.	12 NOVEMBER 1987
D 87-19	871144	SOLUTION GAS PROCESSING PLANT AND CENTRAL OIL BATTERY MANYBERRIES FIELD SHELL CANADA LIMITED	9 DECEMBER 1987
D 87-20	871392	APPLICATION FOR A WELL LICENCE CAROLINE FIELD DOME PETROLEUM LIMITED	9 DECEMBER 1987
D 87-21	871197	WASTE PROCESSING AND DISPOSAL FACILITY - LLOYDMINSTER FIELD SKIMMER OIL SEPARATORS LTD.	

Memo of Decision	860008 860009	Canadian Occidental Petroleum Ltd.	May 19, 1987
	860004 86005 86006 86007	Petrogas Processing Ltd	
Memo of Decision Pre-hearing Donfer.	870621	Small power inquiry	June 10, 1987
Memo of Decision Planning Meeting	870621	Small power inquiry	May 12, 1987

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY NOVACORP PIPELINES LTD. TO CONSTRUCT A PIPELINE AND RELATED FACILITIES

Decision D 87-1
Application 861300

1 INTRODUCTION

1.1 Application

Pursuant to Part 4 of the Pipeline Act, Novacorp Pipelines Ltd. (Novacorp) submitted an application for a permit to construct approximately 162.3 kilometres (km) of 168.3-millimetre (mm) outside diameter pipeline and related facilities for the transmission of condensate and butane from a point in legal subdivision 15, section 17, township 4, range 30, west of the 4th meridian (15-17-4-30 W4M), near Waterton to a point in 14-6-20-2 W5M near Turner Valley. The proposed pipeline is shown on the attached map.

1.2 Hearing

The application was considered at a public hearing in Claresholm, Alberta, on 16 December 1986, with C. J. Goodman, P.Eng., L. A. Bellows, P.Eng., and T. F. Homeniuk, P.Eng., sitting.

Participants at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Novacorp Pipelines Ltd. (Novacorp) H. D. Williamson	E. Shelton, P.Eng. J. Scott, P.Eng. R. H. Seager J. G. Solberg D. M. Bulger, P.Eng. of Shell Canada Resources
Home Oil Company Limited (Home)* R. M. Perrin	
Alberta Recreation and Parks (Recreation and Parks) J. Carpenter	P. Skydt D. J. Perraton
Alberta Environment * D. L. Bratton	
Energy Resources Conservation Board staff H. R. Hansford T. J. Pesta, P.Eng. S. P. Angrave A. L. Larson	

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* Home and Alberta Environment appeared for cross-examination purposes only.

2 ISSUES

The Board considers the issues of the application to be

- the need for and timing of the pipeline,
- pipeline design, safety, and construction, and
- the proposed route.

3 NEED FOR AND TIMING OF THE PIPELINE

3.1 Applicant's Views

The demand for condensate in the United States of America (USA) has been reduced due to the phase-out, by January 1987, of lead as an additive in gasoline. Therefore, Shell Canada Limited (Shell) requires other markets for the condensate from its Waterton gas plant (Waterton). Since the production of heavy oil/bitumen has created a potential domestic shortage of condensate, the markets are seen as any of the heavy oil/bitumen producers. However, initially the condensate would be provided to Shell's heavy oil Peace River Expansion Project and to

Shell's Bowden refinery. Novacorp stated that, since the peak condensate demand for bitumen and heavy crude oil production occurs in the summer months, it is critical for the pipeline to be operating by July 1987. Shell commissioned Novacorp to build and operate the proposed pipeline, which it determined to be the most economic means of transporting the condensate to northern markets.

Since the market for butane in the USA is uncertain, Shell is evaluating the domestic markets as an alternative. Therefore, Novacorp designed the applied-for pipeline to be capable of also transporting butane, should that be necessary in the future. Novacorp acknowledged that additional facilities would be needed to transport butane and that these might be the subject of a future application.

3.2 Interveners' Views

Home did not dispute the need for the pipeline to transport condensate. However, it questioned the need to license the pipeline for butane transportation since Novacorp is not immediately building the extra facilities needed for the transporation of butane.

3.3 Board's Views

The Board accepts that the demand for condensate in the USA has been reduced and that there is a need for condensate transportation from Waterton to other markets. The Board concludes that the pipeline from Waterton to Turner Valley is necessary and is in the public interest.

Considering that Shell is evaluating domestic markets for butane, and since various methods would be available for the transportation of butane from Turner Valley, the Board agrees that the pipeline should also be designed and licensed for butane capability.

4 PIPELINE DESIGN, SAFETY, AND CONSTRUCTION

4.1 Applicant's Views

Novacorp stated that the pipeline would be designed to accommodate the total volume of condensate and butane produced at Waterton. Additional facilities required to handle butane transportation would be installed only when necessary.

Novacorp stated that the pipeline would be designed in accordance with the requirements of the applicable standards and regulations. Leak prevention and detection requirements of the Canadian Petroleum Association Recommended Practice for Liquid Petroleum Pipeline Leak Prevention and Detection in the Province of Alberta would be met or exceeded. A Supervisory Control and Data Acquisition (SCADA) system would be implemented on the pipeline, with continuous supervision from the NOVA, AN ALBERTA CORPORATION Edmonton control centre. Prior to pipeline start-up, Novacorp would complete a procedure manual and a spill contingency plan and would join the Turner Valley/Pincher Creek Environmental Protection Co-operative.

Novacorp stated that, of the eight block valves which would be installed on the pipeline, three would be remotely controlled. The manual block valves could be closed within 90 minutes by personnel stationed in the area.

The pipeline would be designed to accommodate an internal electromagnetic inspection tool. However, Novacorp stated that a baseline survey is unnecessary.

Novacorp stated that, to meet its commitments, the construction of the pipeline must start early in January 1987. It advised that, in accordance with Alberta Forestry, Land and Wildlife requirements, it would construct various river crossings within certain time periods only, to avoid any impact on fish spawning.

4.2 Board's Views

The Board is satisfied that the design, construction, and method of operation of the proposed pipeline meet all the requirements of the Pipeline Act and Regulations. It notes that the interveners did not address these issues.

5 PROPOSED ROUTE

Novacorp advised that it had reached agreements with 94 of the 101 landowners/occupants that would be affected by that portion of the proposed pipeline route located outside the Chain Lakes Provincial Park (Park) boundary and that it expects to complete the remaining negotiations soon. None of the landowners/occupants affected by the portion of the proposed route outside the Park expressed any outstanding concerns or appeared at the hearing.

The Board is satisfied that the portion of the proposed pipeline route located generally outside the Park is acceptable.

The following discussion in this section relates to that portion of the proposed pipeline route located within the Park.

5.1 Applicant's Views

Novacorp stated that the applied-for route through the Park would utilize an existing right of way owned by NOVA, AN ALBERTA CORPORATION and that no additional right of way or new clearing would be required. It confirmed that 18 metres (m) of the existing right of way width would be required for the construction of pipeline through the Park. It argued that, due to the length of the Park, it would not be feasible to use special construction techniques to reduce the width of the area required for construction. It stated that the right of way would be reclaimed to its existing condition, that the best available seeds would be utilized, and that the seeds would be certified to ensure that no new vegetation species would be introduced. Novacorp contended that the applied-for pipeline would not impact the available recreation base within the Park, and that the pipeline would not result in any long-term impact.

Novacorp argued that there are recent precedents for wells and for the installation of pipelines within parks.

Novacorp stated that when it became aware of Recreation and Parks' concerns about the applied-for route through the Park, it evaluated the feasibility of a route adjacent to the Dome Petroleum Limited (Dome) pipeline around the Park.

Novacorp noted that a route parallel to the existing Dome pipeline would increase the capital cost of the pipeline by approximately $100 000, a new 18-m-wide right of way would be required, new landowners would be affected, and the pipeline would be located less than one half kilometre from three residences. It stated that this route would require significant additional clearing and would cross two branches of Willow Creek versus one by the applied-for route. Some of the affected landowners, when contacted by Novacorp, indicated that they would strongly object to a route adjacent to the Dome pipeline.

Novacorp concluded that the applied-for route is the preferable alternative.

5.2 Interveners' Views

Recreation and Parks raised concerns that are related only to that portion of the route that traverses the Park. It stated that installation of the pipeline within the Park would be inappropriate and inconsistent with the present and intended use of the Park, and that it would impact on the Park's resource base.

Recreation and Parks argued that its draft policies, which were developed with considerable public input, do not encourage installation of pipelines within parks. However, it is willing to examine each situation on its own merits. It stated that the Park is the best representation of the Foothills parkland ecosystem available to it, and the impact of the installation of the pipeline would be significant. It suggested that the additional cost of routing around the Park may be partially offset by the increased cost of weed control and revegetation of the right of way through the Park. The pipeline construction would result in new disturbance and Recreation and Parks is concerned that the right of way would not be returned to the present condition.

Recreation and Parks stated that, over the next 15 to 20 years, it is planned that the recreational base of the Park would be enlarged and the camping facilities expanded. The timing and magnitude of the expansion are not finalized. However, installation of the proposed pipeline would reduce the area available for expanding camping and day-use facilities.

Recreation and Parks concluded that the pipeline is not acceptable within the Park, that there appears to be an acceptable alternative route, and that Novacorp has not satisfactorily shown why the pipeline route must traverse the Park.

5.3 Board's Views

On the basis of the evidence presented at the hearing, the Board is not able to determine whether the segment of the proposed pipeline route through the Park is optimum. It recognizes the potential impact of the proposed pipeline on current and future use of the Park. It also recognizes the potential impact to native species of vegetation. However, it is not satisfied that these potential impacts cannot be overcome, either by appropriate mitigation or by adjustment to the actual location of the pipeline. The Board also recognizes the possibility of routing the proposed pipeline outside the Park, including a route parallel to the existing Dome pipeline, and believes such alternatives should be thoroughly evaluated and carefully considered and compared to the proposed route. Therefore, the Board intends to reopen the hearing to consider further the route between points A and B as shown on the attached map.

The Board requests that the applicant submit, to it and to the interveners,

(1) additional information describing possible mitigative measures respecting its proposed route, including possible adjustment to the actual location of the pipeline,

(2) a thorough evaluation of an alternative route generally parallel to the existing Dome pipeline, as well as any other routes the applicant believes should be considered, and

(3) a comparison of the different routes and the applicant's order of preference and the reasons for its choice. The submission should include consideration of such matters as cost, environmental impact, safety, construction difficulties that might be encountered, and any public and landowner reaction. Maps should be included in the submission to provide sufficient detail to allow an analysis of the routes to be made.

Opportunity will be given for those registered as interveners to file evidence respecting the applicant's further submission. Similarly, notice will be provided and opportunity given to any landowners/occupants who would be affected by an alternative route.

6 CONCLUSIONS

The Board concludes that

(a) the pipeline is needed to transport condensate from Shell's Waterton gas plant to markets in north-central Alberta,

(b) the pipeline has been designed in accordance with the proper standards to transport condensate and butane,

(c) the route of that portion of the pipeline located outside the Chain Lakes Provincial Park is appropriate, and

(d) the remaining segment of the route needs further study.

7 DECISION

The Board, pursuant to the Pipeline Act, 1975, is prepared to grant the application of Novacorp Pipelines Ltd. for a permit to construct a pipeline from Shell's Waterton gas plant to about the south end of Chain Lakes Provincial Park (Point A) and from the north end of Chain Lakes Provincial Park (Point B) to connect with the Gulf Valley Pipeline near Turner Valley. The Board will issue a permit to Novacorp Pipelines Ltd. upon receipt of Ministerial Approval by the Minister of the Environment insofar as the application affects matters of the environment.

The Board defers its decision on the portion of the pipeline proposed within the Chain Lakes Provincial Park. Following submission by the applicant of the information requested in section 5 of the report, the Board will reopen the hearing for the portion of the route in the area of Chain Lakes Provincial Park.

DATED at Calgary, Alberta, on 12 January 1987.

ENERGY RESOURCES CONSERVATION BOARD

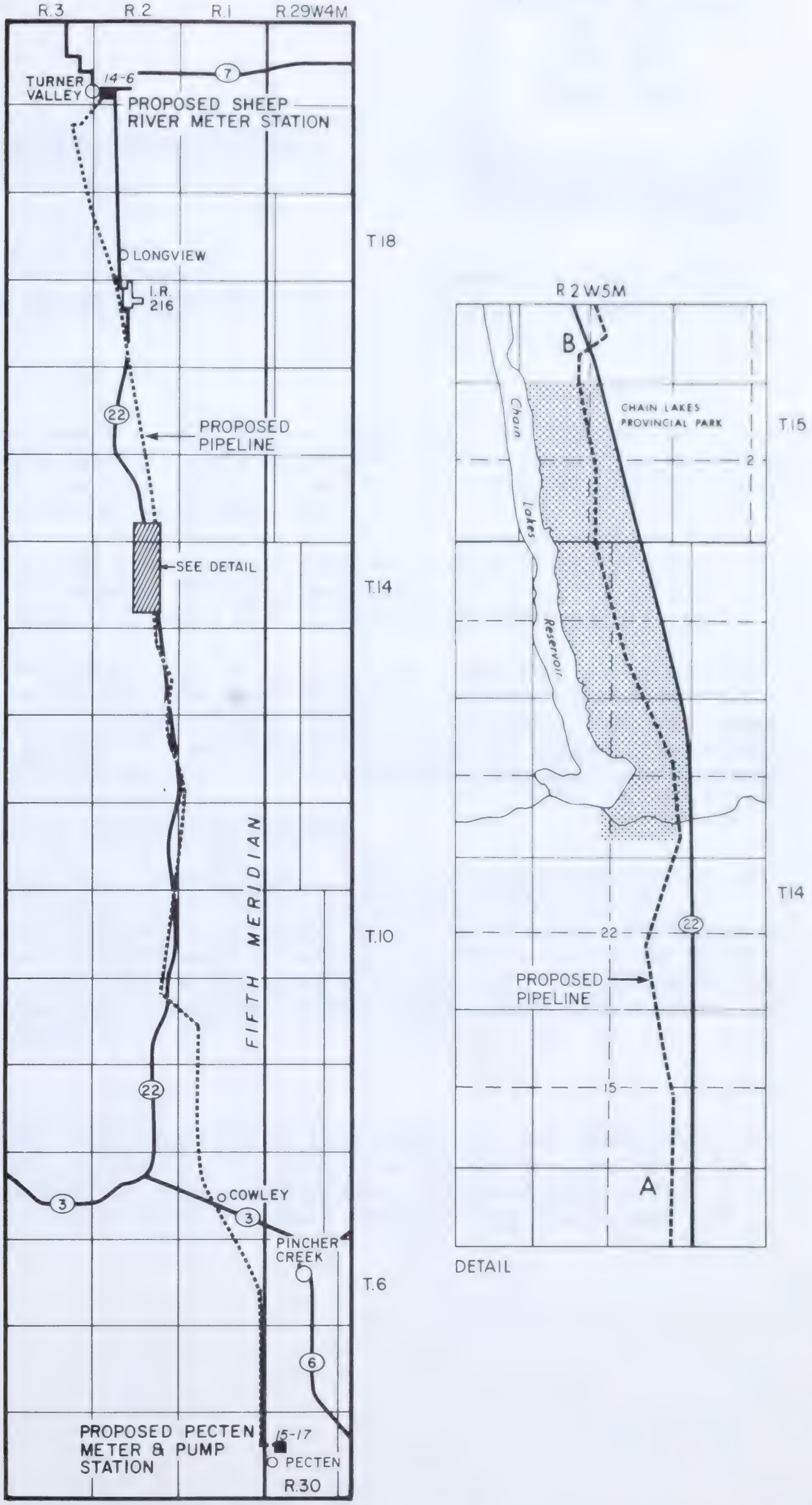
C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

Homeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member

L. A. Bellows, P.Eng., Board Member,
concurs with the contents and with
the issuance of this report.



DETAIL

PECTEN - SHEEP RIVER AREA
APPLICATION NO. 861300
NOVACORP PIPELINES LTD.

D 87-1
ERCB

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY NOVACORP
PIPELINES LTD. TO CONSTRUCT A
PIPELINE AND RELATED FACILITIES

Addendum to Decision D 87-1
Application 861300

Background

Novacorp Pipelines Ltd. submitted an application for a permit to construct approximately 162 km of 168.3-mm outside diameter pipeline and related facilities from a point in Lsd 15-17-4-30 W4 near Waterton to a point in 14-6-20-2 W5 near Turner Valley.

The application was considered at a public hearing in Claresholm, Alberta, on 16 December 1986 and subsequently the Board issued its decision in Board Decision D 87-1 on 12 January 1987.

The Board, for reasons set out in the report, deferred its decision on the portion of the pipeline proposed within the Chain Lakes Provincial Park and requested information on alternative routes in order to compare those to the proposed route. The Board intended to reopen the hearing to consider further the portion of the pipeline that had been deferred.

Information Submitted by the Applicant

In consultation with the intervener, Alberta Recreation and Parks, Novacorp has adjusted its route to satisfy the concerns of the intervener and submitted an amendment to its application. The adjusted route involves two additional landowners, Mr. W. F. Mowatt and Spruce Ranching Ltd., who have no objection to the pipeline. The amended route is also satisfactory to Alberta Transportation, Alberta Environment, and Alberta Forestry.

Decision

The Board accepts the amendment of that portion of the application that relates to the pipeline on which consideration had been delayed. The Board has reviewed the amended application and found it to be satisfactory. Consequently, as there are no outstanding issues, the

Board will not reopen the hearing, and will issue the permit to Novacorp Pipelines Ltd. for the remainder of the pipeline, upon receipt of Ministerial Approval by the Minister of the Environment insofar as the amended application affects matters of the environment.

DATED at Calgary, Alberta on 6 March 1987.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

Bellows

L. A. Bellows, P.Eng.
Board Member

Homeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member

MAY 25

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

TUMIT PETROLEUMS LTD. APPLICATION FOR A WELL LICENCE ACHESON EAST FIELD

Decision D 87-2
Application 861401

1 INTRODUCTION

1.1 Application and Intervention

Tumit Petroleums Ltd. applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to re-enter an abandoned well in legal subdivision 10 of section 30, township 52, range 25, west of the 4th meridian. The purpose of the well, to be known as TUMIT ACHE 10-30-52-25, is to obtain production from the Blairmore and/or Wabamun Formations.

An intervention opposing the application was filed by Cascara Properties Ltd. (Cascara) and Integrated Building Corp. Ltd. (Integrated), the registered owners of the land on which the abandoned well is located. Cascara and Integrated are land developers in the West Edmonton area who, as partners under the name of Lewis Farms, are proposing an urban development.

1.2 Hearing

A public hearing of the application was held in Edmonton, Alberta, on 9 and 10 December 1986, before Board Members V. E. Bohme, P.Eng. and C. J. Goodman, P.Eng. and Acting Board Member T. F. Homeniuk, P.Eng.

2 BACKGROUND

Oil was first discovered in the area immediately west of the city of Edmonton in the 1950s. Substantial development of reserves in the Acheson D-3 A Pool and numerous smaller pools (primarily Blairmore) took place in the 1960s and 1970s (see Map 1). In the early 1980s, the Board had received a number of resource development applications. It also received a number of requests from urban developers to conduct a review of resource-related activity and to develop guidelines for co-existence of oil and gas and land development.

In March 1983 the Board held an inquiry into resource development and urban development in the West Edmonton area and in July 1983 issued Inquiry Report D 83-F. In its report the Board concluded that, with careful planning and co-ordination of activities, the development of both interests could co-exist. The report also established setback distances from oil and gas facilities to urban developments and guidelines and mitigative measures that would reduce the impact of oil and gas facilities in an urban setting.

At the West Edmonton inquiry considerable evidence was put forward respecting the timing of urban, commercial, and industrial development. The land developers speculated that development would commence as early as 1984 and continue for some 15-20

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Tumit Petroleums Ltd. (Tumit) K. R. Anderson	J. C. Forster C. B. Austin, P.Eng. P. M. Cowan, P.Geol. F. I. Whitman L. P. Leonard
Cascara Properties Ltd. and Integrated Building Corp. Ltd. as partners in Lewis Farms (Lewis Farms) D. R. G. Thomas	M. McCullough
Energy Resources Conservation Board staff A. A. Gervais F. G. Sorenson D. K. Boyler	

years. While some of the oil and gas developers contended that the land development projections were optimistic, it was generally agreed that land development would take place prior to the abandonment of the oil and gas operations.

In 1985 Lewis Farms applied for and received from the City of Edmonton approval to prepare an area structure plan for a 2400-acre parcel (portions shown on Map 2) in the West Edmonton area. The area lies west of the Restricted Development Corridor and south of Highway 16 and includes the majority of sections 30 and 31-52-25W4 and sections 25 and 26-52-26W4. Lewis Farms owns approximately 800 acres of the larger area including the majority of the land within section 30-52-25W4.

In early 1958 Union Oil drilled UNION ACHE 10-30-52-25 and placed it on production as a Basal Quartz oil well in March 1958. The well produced a total of 2640 cubic metres of oil prior to its suspension in December 1961. The well remained suspended until it was abandoned in June 1963. Map 2 shows the proposed well site and other wells in the vicinity.

3 ISSUES

The Board considers the issues regarding the application to be

- the need for a well, and
- the location of a well.

4 NEED FOR A WELL

The applicant submitted that the proposed location is in a 32-hectare freehold petroleum and natural gas lease granted to Tumit by the estates of Charles A. and John Welbourn. The lease became effective 30 April 1985 and will expire 29 April 1987 if a well is not drilled in the 32-hectare spacing unit consisting of Lsd 10 and 15-30-52-25W4.

Tumit submitted that it intends to re-enter the surface casing of the abandoned UNION ACHE 10-30 well and sidetrack around the main hole to a total depth of approximately 1340 metres. It stated that the primary purpose of the well is to evaluate the Blairmore pay sands but added that it would also evaluate the hydrocarbon potential of the Wabamun and Glauconitic zones.

Tumit stated that it believed that substantial reserves in the Blairmore had not been previously recovered because of poor completion techniques. It said that only 2 per cent of the original oil in place had been recovered by the UNION ACHE 10-30 well. It estimated that a successful well could recover 10 per cent of the oil in place resulting in the production of approximately 90 000 barrels of oil from the 900 000 barrels in place.

Tumit said that, despite the number of wells drilled to the Basal Quartz in the area, it is difficult to develop a geological correlation because the sands are very discontinuous. A virtually straight hole at 10-30 would allow Tumit to conduct an extensive logging and testing program which would enable it to define the producing zones properly and ultimately maximize recovery from its lands. Tumit argued that, in addition to the added drilling and completing costs, a directional well from an existing location, such as 16-30-52-25W4, could result in it not being able to conduct the tests required to complete a proper evaluation of the reservoir.

Lewis Farms did not dispute the need for a well nor the right of the applicant to the minerals. It stated that it is prepared to accept the technical submission of the applicant with respect to the drilling of the subject well. Lewis Farms added, however, that other operators in the area had directionally drilled recent wells from existing facilities and that it was taking the position that the same technology is available to Tumit.

The Board notes that Tumit has the right to the minerals and agrees that a well is needed to evaluate the hydrocarbon potential underlying Lsd 10-30. The Board also agrees with the applicant that a straight hole in Lsd 10-30 is advantageous both from a cost and technical point of view, but does not necessarily accept the position of Tumit that it must re-enter the UNION ACHE 10-30 well to accomplish its objectives.

The Board concludes that a well which would bottom in Lsd 10-30 is needed to fulfill the contractual obligation of the mineral lease and to provide for recovery of those reserves which otherwise may not be recovered.

5 LOCATION

Although the application is for a licence to re-enter the abandoned well in 10-30, evidence was presented by the applicant and the intervener regarding three alternative locations. In summary, Tumit said that, if its proposed 10-30 re-entry were not approved, it would accept a location anywhere in Lsd 10 where it could drill an essentially vertical well. Lewis Farms' position was that the well should be drilled directionally from the location of the existing well in 16-30, but, if it were necessary to locate in Lsd 10, it preferred that the site be within the proposed golf course or in the area designated as Business-Industrial in its Development Concept Plan. Both applicant and intervener agreed that a suitable location would be in the northwest corner of Lsd 9-30, but the owner of the surface rights was not represented at the hearing.

The Board has considered the suitability of four locations: (1) the 10-30 re-entry applied for, (2) the 16-30 directional well, (3) a well in the northwest corner of 9-30, and (4) a well in the northeast corner of 10-30 (numbered sites shown on Map 2). In its evaluation of these locations, the Board considered the evidence regarding the need for a straight hole and the deviation required to reach the target area in Lsd 10. In addition, the Board evaluated the deviation and the overall risk of drilling to targets in Lsd 9 and 15. It also considered the total cost to complete a well into Lsd 10 from the various locations, including drilling, completion, lease, road, and pipeline costs. It did not take into account the potential $50 000-well-servicing assistance grant raised by Tumit because the evidence for such an award was uncertain. It considered the impact of the alternative locations on Lewis Farms' development plans and the unrecovered costs of including a well site in the development. The views of the applicant, the intervener, and the Board are set out below for each location considered.

(1) 10-30 Re-entry

Tumit said that this location gave it the advantage of using an existing surface casing string and obtaining a basically vertical well to ensure that the necessary drill stem tests could be run to evaluate the pay zone. Drilling costs were estimated to be some $257 000, about $37 000 more than for a normal non-deviated hole. It also suggested that the well might qualify for a $50 000 grant under an Alberta government well-servicing assistance program. The cost of surface lease, access road, pipeline, and well completion would be added to the drilling cost to arrive at the total cost of a producing well.

Lewis Farms pointed out that the 10-30 well was in the middle of a designated residential zone shown in a development concept plan presented at the hearing. It provided detailed costs of servicing lots in its proposed development and estimated that its overall costs would be about $100 000 per developed acre. It suggested that the well could be accommodated within a proposed golf course some 100 metres south of the proposed site.

The Board accepts that the 10-30 re-entry site would have a serious impact on the current Lewis Farms plan for the area. The Board sees no particular advantage in re-entering the abandoned 10-30 well and believes that extra costs involved in such a re-entry and sidetrack could easily offset the potential $50 000 grant. Additional lease, pipeline, and road costs would also be incurred. A location within the golf course would entail a highly deviated well to reach a target area in Lsd 15, if 16-hectare spacing were to proceed. The Board does not believe that re-entry into the 10-30 well is the best alternative.

(2) 16-30 Directional Well

Tumit said that a directional well from the 16-30 site would be a high-cost, risky operation, with a low possibility of running the tests required to evaluate the pay zone for future completions. It said that the cost to drill such a well would be about $325 000 and about $400 000 total cost to complete it, with the possibility of reaching $500 000 if problems were encountered during the directional drilling. Tumit claimed that the 16-30 location was muskeg. Although it had recently been stabilized with 2 to 3 metres of fill, it would not support a drilling rig.

Lewis Farms supported the 16-30 location. It submitted that drilling from that site would follow the recommendations of the Board's D 83-F inquiry report and not affect its current development plans. No new well site would be required since a well is currently completed at 16-30. No access roads or pipeline easements would be required for the proposed well in 10-30 or possible wells in Lsd 9 and 15. The distance to a proposed central battery in the Restricted Development Area in 12-20-52-25 would be very short.

The Board accepts that a reasonably vertical hole would be necessary to run the testing program proposed by Tumit. It also agrees that the risks associated with a deviated well exceed those of a vertical well, although no additional lease or pipeline costs would be incurred at 16-30. Large deviations would also be necessary to reach targets in Lsd 9 and 15 from the 16-30 location, if 16-hectare spacing were instituted.

Given that Lewis Farms' planning is still in the conceptual stage, the Board believes that a more suitable location than 16-30 can be found which would reduce the cost and risk, yet not seriously impact Lewis Farms' planning. Such a site should provide a reasonable opportunity for Tumit to complete a well, at reasonable cost and risk, in Lsd 10 as well as in Lsd 9 and 15.

(3) NW Corner of 9-30

Tumit said it would not object to a location in 9-30. However, it had not negotiated with the surface owner and had no indication that it could obtain a surface lease.

Lewis Farms stated that a location in 9-30 could be fitted into its current planning and it supported such a location, although it did not own the surface rights.

The Board accepts that 9-30 would be an acceptable surface location for a well to be completed in 10-30 and would provide for reasonable deviations to wells in Lsd 9 and 15. It assumes that costs would be similar to those of re-entering the 10-30 well or drilling a well in the northeast corner of 10-30. Some directional drilling would be necessary to reach 10-30, increasing costs somewhat, but access road and pipeline costs would be slightly reduced. Since the owner of the 9-30 site was not represented at the hearing, the Board does not believe it can make a decision regarding that location without hearing whether or not the owner would object. However, if Tumit were able to negotiate a surface lease with the owner, the Board would accept the northwest corner of 9-30 as a suitable site.

(4) NE Corner of 10-30

Tumit indicated that a location in the northeast corner of Lsd 10 would be acceptable. It would provide an opportunity to complete an essentially vertical well in 10-30 and the deviations to Lsd 9 and 15 would be reasonable.

Lewis Farms opposed any location in Lsd 10 and pointed out that this location did not fit its current development concept because it would encroach on a proposed school site and would entail moving a roadway into an unsuitable location.

The Board believes that a location in the northeast corner of Lsd 10 would provide a virtually straight hole into the target area in Lsd 10 and its cost would not be greater than the re-entry into the abandoned 10-30 well. It provides short-deviation access to targets in Lsd 9 and 15. Pipeline and access roads would be shorter than for the 10-30 re-entry location. It is close to an area which Lewis Farms acknowledged to be suitable for a well site and the Board believes that Lewis Farms' current development concept could be altered without serious impact on the overall plan.

Therefore, the Board believes that a location in the northeast corner of Lsd 10 is the best alternative for the proposed well and for the overall development of the northeast quarter of section 30.

6 CONCLUSION

After careful consideration of all of the evidence, the Board is not satisfied that the applied-for location at the 10-30 re-entry site is the best location for the proposed well. Rather, the available evidence suggests that a location in the northeast corner of Lsd 10-30-52-25W4 would be preferable, given the current status of Lewis Farms' planning for the area. Alternatively, a well location in the northwest corner of Lsd 9, although more costly, may be appropriate, if the owner of that land were to agree to such a location.

7 DECISION

The Board denies Tumit Petroleum Ltd.'s application for a well at the applied-for location, without prejudice to any further application which Tumit may wish to make.

DATED at Calgary, Alberta, on 16 January 1987.

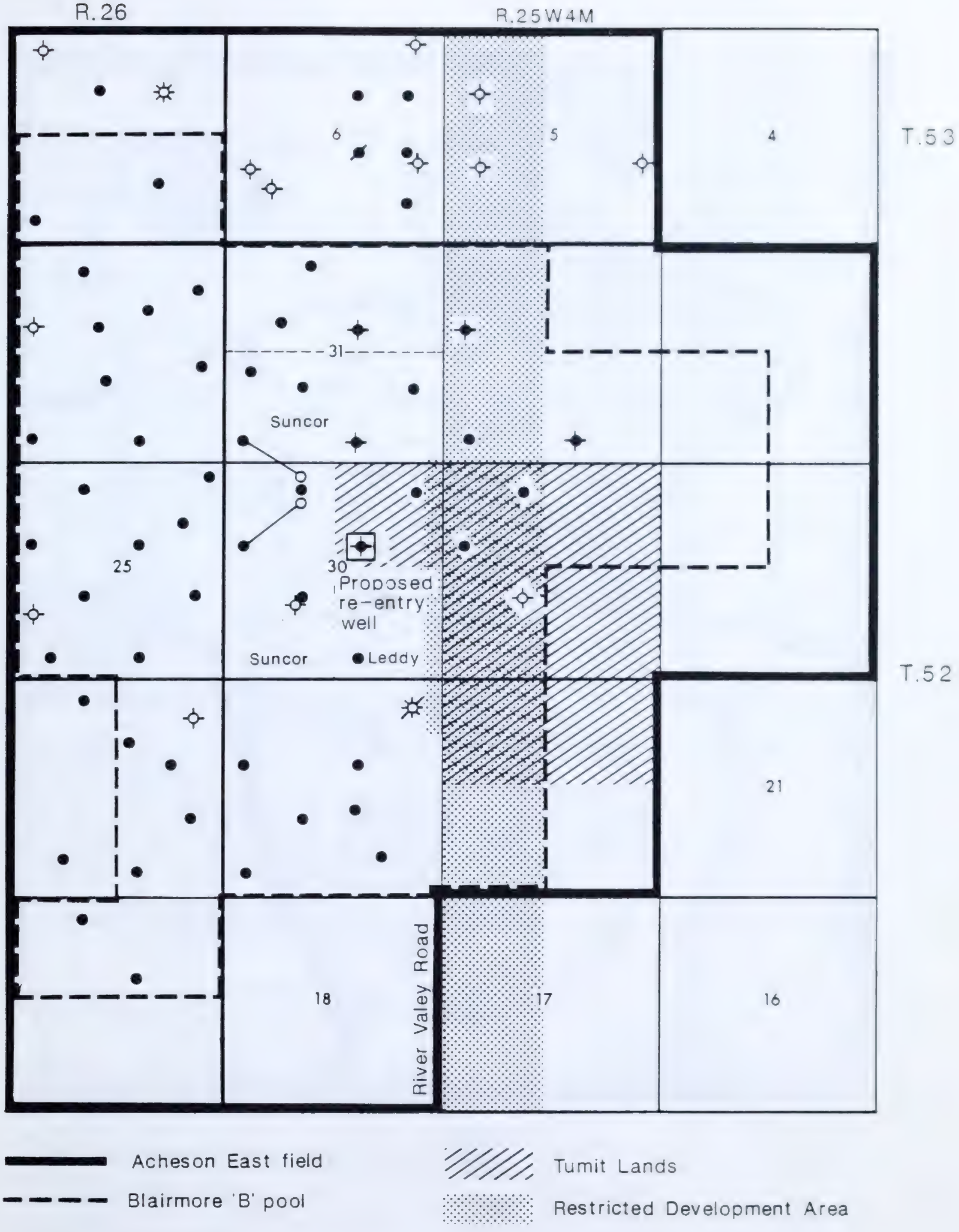
ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

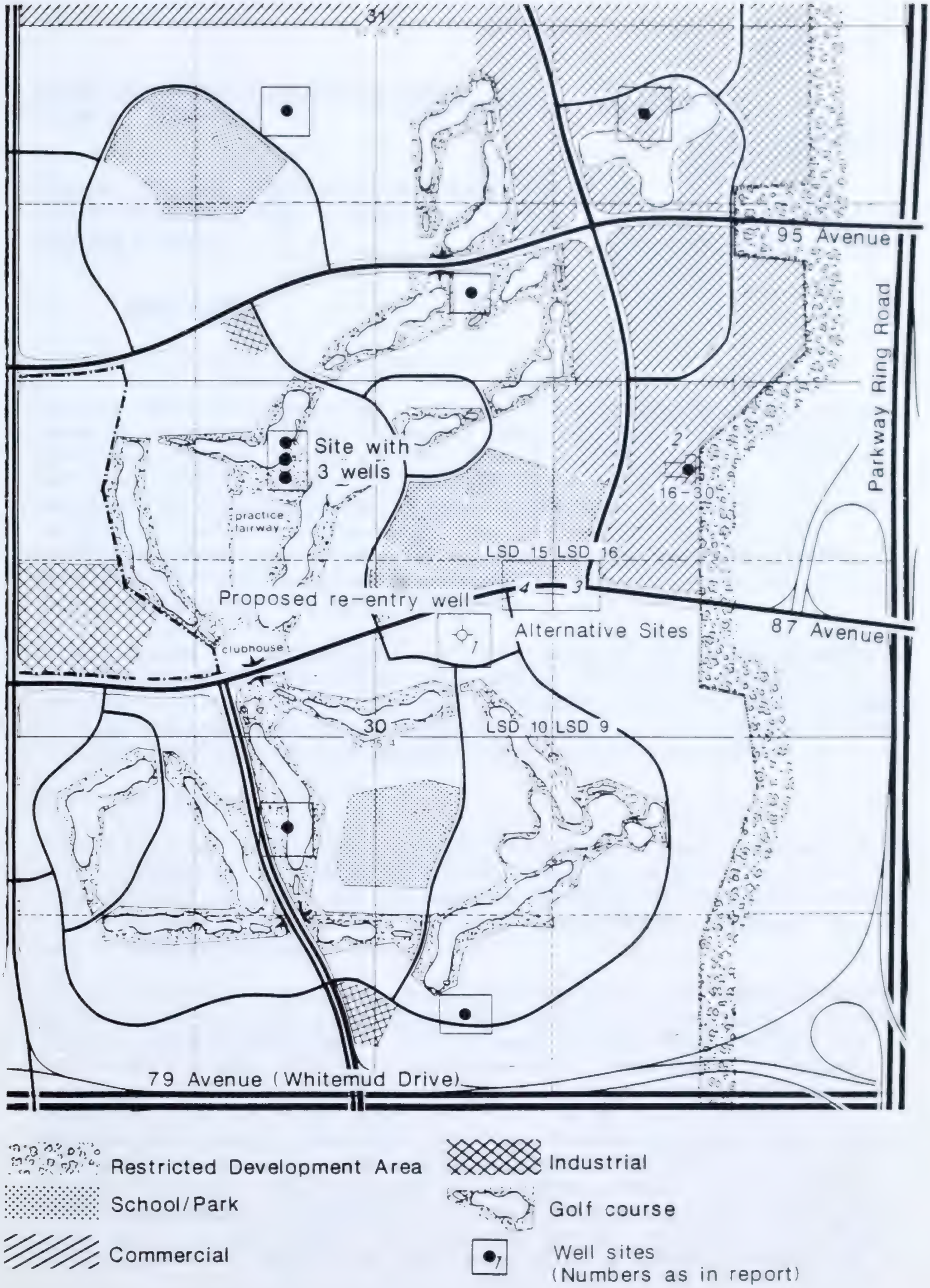
C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member



MAP 1 OILFIELD DEVELOPMENT IN THE ACHESON EAST FIELD



MAP 2 LEWIS FARMS DEVELOPMENT CONCEPT

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DIAMOND SHAMROCK EXPLORATION OF CANADA, LTD.
APPLICATION FOR A WELL LICENCE — Decision D 87-3
PEMBINA FIELD — Application 861141

1 INTRODUCTION

1.1 Application and Intervention

Diamond Shamrock Exploration of Canada, Ltd. (Diamond Shamrock) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a well licence to drill a well from a surface location in legal subdivision 10 of section 14, township 47, range 1, west of the 5th meridian, to a projected bottom-hole location in legal subdivision 16 of section 10, township 47, range 1, west of the 5th meridian, which underlies Pigeon Lake. The proposed well is to be known as DIASHAM PEMBINA 16-10-47-1 (the well), and would be for the purpose of obtaining oil production from the Leduc Formation.

Interventions to the application were received by the Energy Resources Conservation Board (the Board) from various landowners, ratepayers, residents, cottage owners, and summer villages in the vicinity of Pigeon Lake and the proposed well. Those who appeared at the hearing to speak to their interventions are identified in the following table.

1.2 Background

Pigeon Lake is located approximately 90 kilometres (km) southwest of the city of Edmonton. It is an extensively used recreational area that supports both permanent and seasonal residences. The population of the lake area varies greatly from winter to summer months, although the lake may be used for winter recreation.

In the 1950s the Bonnie Glen Field was developed in the Leduc Formation northeast of the lake and includes approximately sixty-two wells within 2 km of the southeast shore. Oil and gas activity near the lake was reactivated in the 1980s with the majority of development occurring along the north shore. There are currently twenty-three oil wells producing from the north shore area, with three wells licensed but awaiting drilling. These wells are directionally drilled under Pigeon Lake and targeted to a depth of approximately 1250 metres (m) to the Cardium Formation which contains sweet hydrocarbons. The majority of the Cardium wells are drilled from common surface locations along the north and northeast shores and have from one to five wells on a single site (Figure 1). Production from these wells is either trucked from a tank on the lease or pipelined to a battery. The associated gas is either flared on site or pipelined to an associated gas plant.

The proposed well is located on the central northern boundary of Pigeon Lake and is in the vicinity of the summer villages of Itaska Beach, Golden Days, Argentia Beach, and Mulhurst (Figure 2).

1.3 Hearing

A public hearing of the application was originally scheduled to commence on 3 December 1986. Prior to commencement the Board received requests from interveners to re-schedule the hearing. The Board granted the requests and the hearing was re-scheduled for 16 December 1986. The Board received additional requests for further adjournment and therefore held a pre-hearing meeting in Edmonton on 26 November 1986 to consider these requests. At the commencement of this proceeding, the Department of the Environment informed the Board, the applicant, and the interveners that a formal order had been issued by the Minister of Environment requiring that Diamond Shamrock compile an environmental impact assessment for its drilling program in the vicinity of Pigeon Lake. After consideration of the arguments, the Board decided that the hearing be re-scheduled to 13 January 1987.

The hearing was then opened on 13 January 1987 and continued on 14 and 15 January 1987, in Edmonton, Alberta, before Board Members V. E. Bohme, P.Eng., L. A. Bellows, P.Eng., and Acting Board Member H. Antonio, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Diamond Shamrock Exploration of Canada, Ltd. (Diamond Shamrock) D. G. Davies	D. Belczewski, P.Eng. R. Bisset, P.Eng. G. Heming, P.Eng. D. James T. Morey
The Summer Villages of Sundance Beach, Silver Beach, Argentia Beach, and Grandview. The Sisters of Charity of Providence of Western Canada, The Sisters of Charity - Immaculate Conception, The Sisters of Ursulines of Jesus. Individual ratepayers of the Summer Villages of Golden Days, Sundance Beach, Silver Beach, Argentia Beach, and Grandview. R. B. Davison D. F. Pawlowski	K. Armstrong P. M. Dranchuk, P.Eng. G. Williams, P.Geol.
Summer Village of Itaska Beach D. Konelsky	
Summer Village of Poplar Bay (M. Kane) M. Kane	M. Kane
R. M. Curtis (Mr. Curtis)	R. M. Curtis
G. F. Gaetz (Mr. Gaetz)	G. F. Gaetz
H. Neufeld (Mrs. Neufeld)	H. Neufeld
E. J. Slatter[1] (Mr. Slatter)	
P. Norris	P. Norris
Alberta Environment[2] F. Schulte	
Energy Resources Conservation Board staff H. R. Hansford D. Eresman R. L. Paulson, C.E.T. N. F. Lord, C.E.T.	

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[1] R. M. Curtis, counsel for Mr. Slatter, tendered his intervention; however, no one appeared to speak to the intervention.

[2] Mr. F. Schulte appeared on behalf of Alberta Environment solely for the purpose of cross-examination with respect to the environmental impact assessment.

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the nature of production from the proposed well,
- the location of the well,
- the impact of the well,
- the emergency plan.

3 NEED FOR THE WELL

3.1 Views of the Applicant

Diamond Shamrock submitted that by virtue of a petroleum and natural gas lease issued by the Alberta Government, it had acquired the right to explore for and exploit the oil and gas present in the drilling spacing unit comprising the northeast quarter of section 10, township 47, range 1, west of the 5th meridian. Further, the well was required to test Diamond Shamrock's geological interpretation which, if proved correct, would result in drilling three additional wells to develop a small pinnacle reef. Diamond Shamrock submitted that the recoverable reserves could be as high as 13.5 million cubic metres (10^6 m^3) of oil and therefore the well would benefit the Province of Alberta by proving up additional reserves and supplying additional royalty payments. Diamond Shamrock also stated that it had already spent a large amount of money in acquiring the lease and developing the geological interpretation of the potential oil pool and that the well was necessary to recoup these expenditures and generate income for the company.

3.2 Views of the Interveners

Generally, the interveners did not question Diamond Shamrock's right to drill the proposed well; however, they did question the need to proceed with the proposed well due to the possibility of the well encountering fluids that contain hydrogen sulphide (H_2S). The interveners stated that the well should not be permitted in what they submitted was an environmentally sensitive and popular recreational area. They also argued that any oil which might be produced from the well was not needed at the present time and that oil in less environmentally sensitive areas should be developed first.

3.3 Views of the Board

By virtue of obtaining the right to recover oil and gas which may underlie the leased area, the Board accepts that Diamond Shamrock has the right to drill for such hydrocarbons. This right, however, is subject to compliance with the Oil and Gas Conservation Act (the Act). Therefore, consistent with the purpose of the Act, the need for the well must be weighed against any adverse safety, social, and environmental impact which may arise during drilling and production operations. The evidence and the Board's views of the benefits and the impacts are set out in the following sections of this report.

4 NATURE OF PRODUCTION OF THE PROPOSED WELL

4.1 Views of the Applicant

Diamond Shamrock stated that it interpreted seismic survey data to indicate a Leduc Formation pinnacle reef located under Pigeon Lake. The applicant anticipated this reef to be 150 to 180 m thick and to contain an estimated 13.5 10^6 m^3 of recoverable oil. Diamond Shamrock believed that the seismic character and geological setting of this Leduc anomaly is analogous to the Golden Spike Leduc limestone reef. The Golden Spike reef contains sweet oil which the applicant attributes to an underlying tight Cooking Lake Formation platform which has prevented the formation or encroachment of H_2S into the reservoir. In contrast, the presence of a porous Cooking Lake Formation platform under the Leduc-Rimbey chain of reefs, to the east of the Golden Spike Field and the proposed well, has resulted in the migration of H_2S into these reservoirs. Wells drilled between the expected pinnacle reef and the adjacent Bonnie Glen Field and regional geological evidence indicated that a non-porous Cooking Lake Formation platform should exist in the proposed well and as a result the well should contain sweet oil.

Due to the presence of H_2S in the general area and as a prudent operator, Diamond Shamrock proposed to drill the well as if it anticipated encountering H_2S. The estimated concentration of 0.13 per cent H_2S was obtained from the well, 6-29-47-27W4M, located in the Bonnie Glen Field. This value and a corresponding release rate of 0.057 cubic metres per second (m^3/s) of H_2S were then used in designing the drilling program, the production operations, and in formulating an emergency response planning zone.

4.2 Views of the Interveners

Expert witnesses for the cottage owners agreed in part with the applicant's choice of the Golden Spike Leduc Pool as an appropriate analog for the proposed well. The interveners believed, however, that it was more reasonable on a statistical basis to expect fluids at the proposed well to be similar to those encountered in the adjacent Bonnie Glen Field and hence contain some H_2S. They noted that Texaco, in recent applications made to the Board for wells in the Bonnie Glen Field, used an H_2S concentration of 0.29 per cent in planning wells. They believed that the Cooking Lake Formation could be porous in the area of application and therefore migration of H_2S into the reservoir could have occurred, although they had not conducted a detailed study of nearby wells.

The interveners did not state what exact level of H_2S would be encountered in the reservoir, but said the levels could range from 0.13 to 3.76 per cent. Release rates were estimated to range from 0.27 to 2.8 m^3/s using H_2S concentrations from 0.13 to 0.675 per cent. The interveners estimated a range of contingency planning zone radii from 937 to 4641 m but did not recommend a specific radius to be used. The interveners stated that it would be appropriate for Diamond Shamrock to anticipate and plan for the worst possible scenario.

4.3 Views of the Board

The Board finds the geological scenario as interpreted by Diamond Shamrock to be reasonable and accepts the possibility that sweet oil may be encountered in the reef. The Board finds, however, that for planning purposes it is appropriate for the applicant to anticipate encountering some level of H_2S. The Board believes the estimated release rate used by Diamond Shamrock to be somewhat low given the uncertainty of the maximum expected H_2S content and flow rates presented in evidence at the hearing. The Board finds that the release rates presented at the hearing extend over a very large range and the application of any particular rate would have an uncertain technical basis. The Board has considered the most probable maximum rate and the area most likely to be affected by the rate. The Board suggests that a release rate in the range of 0.8 to 1.2 m^3/s would be more applicable for planning purposes. This would be in the middle range of the interveners' estimates and some twenty times the applicant's proposed rate. The emergency planning zone should provide for the potential evacuation of persons in a portion of the nearest beach which could be affected. If the well is drilled and found productive, the release rate and emergency planning zone would then be based on actual flow rates and analysis of the well fluids.

5 LOCATION OF THE WELL

5.1 Views of the Applicant

Diamond Shamrock stated that it had considered four alternative well locations, but believed that the proposed site was the most desirable because

- the location was not visible to residents due to the density of trees and brush,
- a surface lease had been acquired from the landowner,
- an existing access road would be utilized to drill the proposed well, and
- there are no residents within at least 400 m of the well.

Further, as the well was to be directionally drilled it was desirable to minimize the deviation from a cost, safety, and risk standpoint. Due to these factors, Diamond Shamrock believed it had chosen the most appropriate location. The alternatives considered had been ruled out as they would result in undesirable cost or situate the well closer to the residents of Pigeon Lake or to residents of farms or small holdings north of the well.

5.2 Views of the Interveners

The interveners were of the opinion that there was no location from which Diamond Shamrock could drill the well which would alleviate their concerns. They therefore contended that the project as a whole should be abandoned or postponed pending a more thorough investigation of the proposed development. An inquiry or a comprehensive development plan was suggested as necessary prior to deciding on whether or not any location was suitable.

5.3 Views of the Board

The Board evaluated the proposed location factors such as visual screening, road access, distance from the lake, and the length of deviation to the well target. It also observed that the alternative locations would not remove the well farther from a number of inhabitants around Pigeon Lake. The Board therefore finds that if the well is to proceed, the proposed location would be appropriate.

The Board also considered submissions made at the hearing that a broader type of inquiry or hearing should be convened to consider plans for future oil and gas development in the area. It notes that the proposed oil field, if found productive, would require only three more wells to develop it. In addition, the Cardium Formation underlying the lake now appears to be almost completely developed. The Board does not believe that a general inquiry would be appropriate unless new evidence indicated the presence of another field which would require further and more extensive drilling.

6 IMPACT OF THE WELL

6.1 Views of the Applicant

Diamond Shamrock stated that it did not believe that the proposed well would cause any greater impact on the inhabitants and the environment of Pigeon Lake than those wells already existing in the area. As Diamond Shamrock anticipated sweet oil, there would not be adverse safety or environmental impacts from H_2S. Further, Diamond Shamrock proposed to use whatever measures were required to ensure that no contamination or environmental damage would occur during the drilling and production phases. These measures would entail such precautions as diking the lease and utilizing a remote sump for drilling. The lease area would be fenced and locked. Rig exhausts would be positioned away from residents, engines would be muffled, and operations would be conducted in such a manner as to reduce noise to the lowest possible level. After a production test period, the well production would be pipelined to a remote facility. Flaring at the well would be through an elevated flare stack, equipped to ensure continuous burning and designed to mitigate noise and to disperse any sulphur dioxide over a large area.

Moreover, in order to ensure the least possible impact, Diamond Shamrock stressed that it was essential that it be allowed to proceed with the well during the winter months when the number of persons utilizing the area was the least.

6.2 Views of the Interveners

The interveners submitted that due to the potential of encountering H_2S, the well could have a detrimental impact on their health, their lifestyle, and the environment of the Pigeon Lake area. From an environmental perspective, the interveners believed that the well could cause such adverse impacts as contamination of Pigeon Lake and the water supply of the area, and damage to trees and animals from a release of H_2S. The interveners were not satisfied that the impact study submitted by Diamond Shamrock was detailed enough or conducted over a sufficiently long period of time to assess adequately what environmental damage could occur.

The interveners believed that a very real impact existed, as the safety of residents could be in jeopardy. They believed that the applicant had not sufficiently addressed the safety aspects of drilling and producing the proposed well.

The interveners said that their lifestyles in the area could be disrupted through such impacts as odours, noise, increased traffic, and flaring of gas. They expressed concern that the wildlife which they enjoyed in the area would not be protected and would be driven away. In addition, they believed that the presence of the well could also devalue property along the lake.

6.3 Views of the Board

The Board is of the opinion that drilling the applied-for well should have very little impact on the environment close to the well site. The Board does recognize, however, that the lake and the beach area near the lake are highly sensitive and are utilized extensively for recreation; therefore any energy-related development must be scrutinized in relation to that area. To this end, the Board believes that any development must be neat, safe, compact, and conscientiously developed in harmony with the use of the lake and the beach. It does not believe that the area removed from the beach is as sensitive nor as heavily utilized. Nonetheless, the Board would expect an operator to conduct its operations under special conditions which recognize the sensitivities of the lake, the beach, and the surrounding natural areas. If the well is proven to be productive, a separate approval would be required for the necessary production facilities.

7 EMERGENCY PLAN

7.1 Views of the Applicant

Diamond Shamrock stated that the emergency response plan presented was only a draft and that it would be revised based on input received at several recent public meetings with the local summer villages and residents. Also, any useful input received at the hearing would be incorporated into the response plan.

Using an H_2S concentration of 0.13 per cent and a corresponding release rate of 0.057 m^3/s, Diamond Shamrock used a 400-m emergency planning radius. The applicant further stated that the area within the planning radius contained no residents. The closest residents were located in the Summer Village of Argentia Beach approximately 800 m from the well.

Diamond Shamrock submitted that it intended to establish an office in the area which would be manned 24 hours a day to provide information or answer any questions during the drilling of the well. It also would have a mobile air monitoring unit on location during the drilling of all sour formations. The unit would begin monitoring at the first stages of any emergency. If the monitor should read H_2S concentration of 1 part per million (ppm) or greater over a 1-hour average, residents in the affected area would be asked to evacuate.

Diamond Shamrock also stated that if it was apparent that released H_2S gas might endanger the life or health of any individual or might cause a serious environmental contamination, the well would be ignited. The well would also be ignited if an H_2S reading of 5 ppm or greater for a 1-hour average was recorded by the mobile monitor at any occupied residence, or if monitoring was not taking place due to some unforeseen circumstance.

7.2 Views of the Interveners

In general, the interveners believed that the emergency response plan proposed by Diamond Shamrock had a number of deficiencies and was not adequate to protect the safety of local residents.

They stated that the emergency planning zone should be significantly increased. They suggested that the worst-case situation should be used; however, they did not indicate which release rate would be reasonable to use in determining the emergency planning radius. The interveners recommended the following items be addressed in the emergency plan:

- greater co-operation between municipal authorities and applicant in the co-ordination of the plan,

- emergency services be arranged in advance of drilling,

- liaison with organized groups be established,

- seasonal residents report their presence to the applicant,

- high-risk groups such as elderly, chronically ill, and children be identified and given special priority in an evacuation plan,

- individuals lacking transportation be identified,

- a system of notifying residents be developed prior to drilling,

- emergency response team be available to the patrol area, and
- evacuation routes for each resident be included.

7.3 Views of the Board

The Board does not believe Diamond Shamrock's proposed emergency response plan would be adequate given the circumstances, since the well is being drilled in a unique recreational area. The area has a small base of permanent residents with a fluctuating number of seasonal residents. This fact, along with some uncertainty respecting the type of fluid which might be encountered and the potential release rates, leads the Board to believe that some additional emergency planning consideration should be introduced at this well.

The Board suggests that Diamond Shamrock's emergency planning radius should not be simply a circle based on a defined or selected H_2S release rate. Diamond Shamrock should consider a planning zone which concentrates on the population most likely to be affected by a release of H_2S. That would include all of Argentia Beach and part of the Summer Village of Golden Days.

The plan should include an inventory of all permanent residents as normally required in emergency response plans. The seasonal residents would not necessarily need to be inventoried in the same manner, but the plan should include procedures to ensure that the seasonal residents are adequately protected by utilizing some of the items suggested by the interveners under Section 7.2.

An emergency response plan for the production phase of the well, if one should be required, would be developed based on the Board's normal criteria.

8 CONCLUSIONS

The Board recognizes the high level of concern expressed by many property owners near Pigeon Lake. It is also cognizant of the rights granted to the applicant when it acquired the petroleum lease on which the proposed well would be drilled. The Board's conclusions, set out below, are based on a carefully considered balance between the realistically anticipated impacts of the proposed well on the property owners and the environment on one hand, and the benefit to the public and the applicant of developing a productive oil or gas field.

(1) With careful management, and under the Board's strengthened sour gas drilling requirements, the probability of losing control of the well and not igniting it are low and, in the Board's view, acceptable.

(2) Production operations can, in the Board's view, be carried out with minimal impacts provided that careful management of the operations is carried out by the operator (under conditions to be approved by the Board).

(3) Pigeon Lake area has been developed extensively for both sweet and sour oil and gas production for many years, with little impact on the residents near the lake. The Board expects that under its current requirements for well safety, the proposed development, whether sweet or sour, will not produce greater impacts than those currently resulting from similar oil field developments.

(4) The Board believes that over all, the real impacts of drilling and producing the proposed well are not sufficient to deny the application.

9 DECISION

Having reviewed the evidence, the Board is satisfied that, based on the undertakings presented by the applicant at the hearing, the well can proceed without significant impacts on the area or residents. A licence will be issued when a satisfactory emergency response plan is submitted in a final form to the Board. Application 861141 is hereby approved.

10 CONSIDERATIONS FOR FUTURE DEVELOPMENT

A number of matters were brought up during the hearing which were indicated to be of concern to the interveners if the application were to be approved. The Board believes that it should comment on those matters in the report even though they do not relate directly to the application.

To further ensure that impacts of drilling and producing are kept to the minimum, if oil or gas is discovered, the Board would require an applicant to follow the special conditions set out below:

- Area residents must be consulted with respect to safety and emergency planning prior to drilling.
- A means of continuing consultation and communication with the residents shall be set up, perhaps through the village councils or other representative groups.
- The Board would restrict well testing at a single battery on the well site to a minimum and would expect the construction of pipelines to remote battery sites to commence immediately upon completion of the test period. Both pipelines and production facilities would be subject to separate application and approval by the Board.
- Drilling close to residential areas would be permitted only during the off season, preferably during winter.
- The Board would take special and immediate action on the occasion of any complaint regarding noise, odour, excess traffic, or unsightly facilities.

- The Board would review subsequent well licence applications to ensure the minimum amount of land is cleared for well sites.

- The operator would be required to fence, landscape, and maintain well sites in a manner consistent with the natural area in which they are situated.

- The Board would provide frequent inspections of the facilities and advise residents and village councils how its field staff may be contacted.

DATED at Calgary, Alberta, on 4 February 1987.

ENERGY RESOURCES CONSERVATION BOARD

Bohme

V. E. Bohme, P.Eng.
Board Member

Bellows

L. A. Bellows, P.Eng.
Board Member

Antonio

H. Antonio, P.Eng.
Acting Board Member

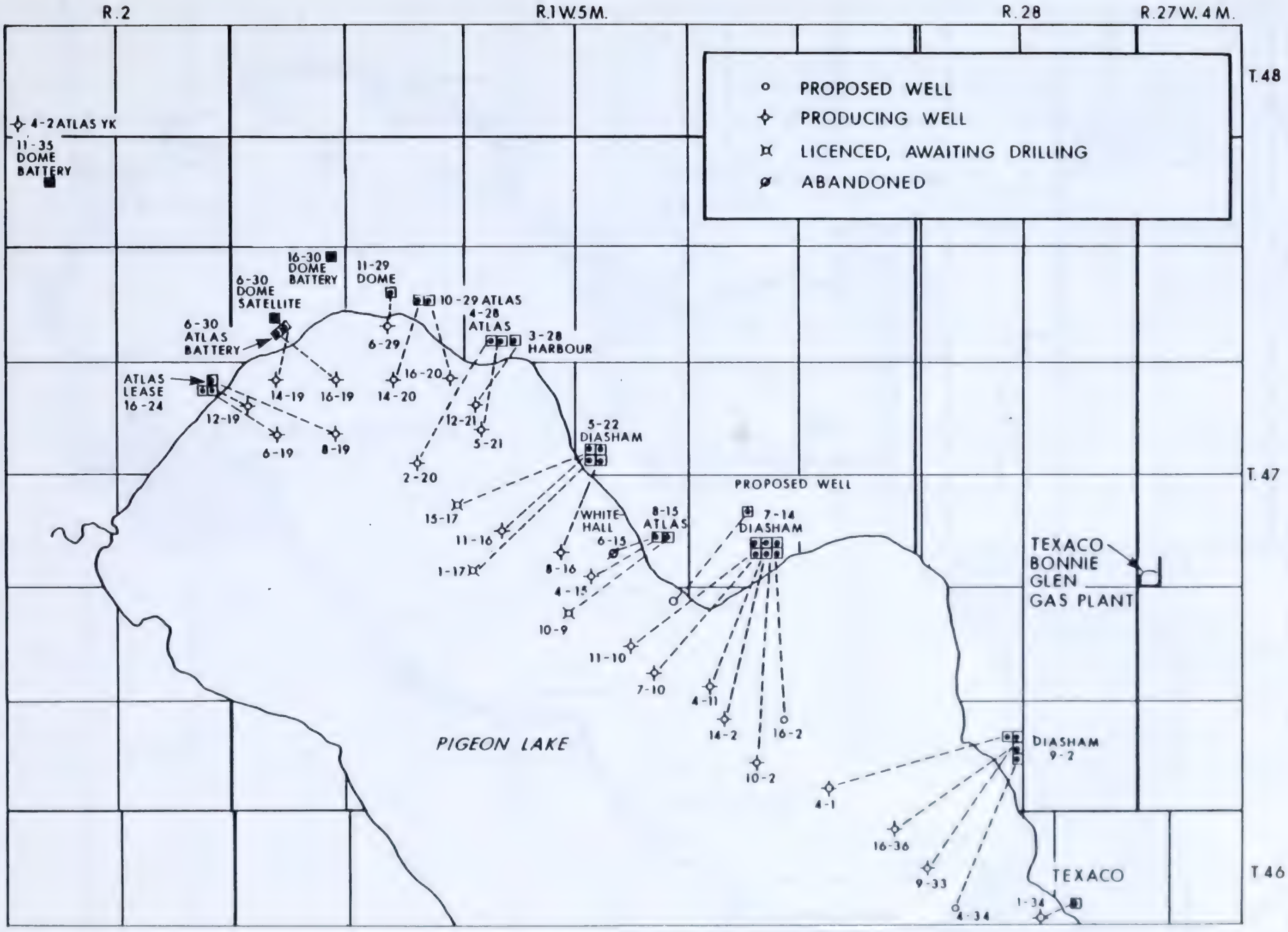

FIGURE 1 CURRENT SHORE LINE OIL AND GAS DEVELOPMENT

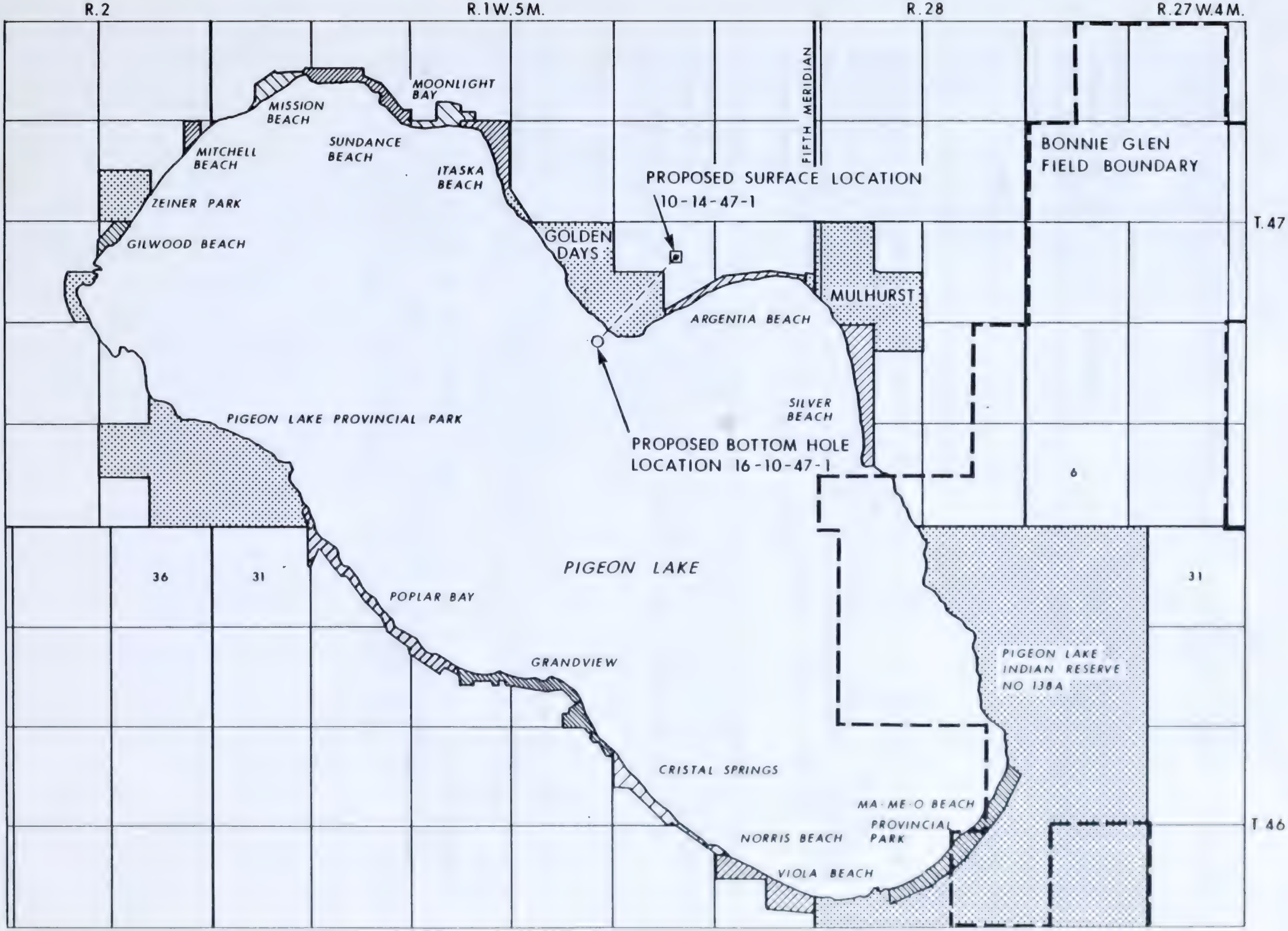

FIGURE 2 PIGEON LAKE AREA

UNIVERSITY OF ALBERTA
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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

COREXCAL, INC.
APPLICATION FOR A WELL LICENCE
WEST DRUMHELLER AREA

Decision D 87-4
Application 861614

1 INTRODUCTION

1.1 Application and Intervention

Corexcal, Inc. applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well in legal subdivision 1 of section 19, township 29, range 20, west of the 4th meridian. The proposed well, to be known as COREXCAL WEST DRUMHELLER 1-19-29-20 (the well), would be for the purpose of obtaining oil production from the Nisku Formation (Nisku).

Interventions to the application were received by the Energy Resources Conservation Board (the Board) from Mr. and Mrs. R. Raketti, landowners adjacent to the proposed well, and the City of Drumheller. A submission in support of the application was received from George Buchta, the surface owner of the well site.

1.2 Hearing

A public hearing of the application was held on 3 February 1987, in Drumheller, Alberta, before Board Members V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and Acting Board Member E. G. Fox, P.Eng.

At the conclusion of the formal presentation of evidence and argument, hearing participants and the Board viewed the proposed location by visiting the Raketti's residence site, the proposed well site, and the Tyrrell Museum in the valley below the proposed well site.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Corexcal, Inc. (Corexcal) R. A. Neufeld	D. W. Barnett, P.Geol. R. P. Burns A. M. Chinnick, P.Eng. M. B. Schroeder, M.Sc.
Mr. and Mrs. R. Raketti (the Rakettis) E. D. Chapelski	Mr. Raketti Mrs. Raketti
The City of Drumheller (the City) R. D. Ross	R. Ramanetz
George Buchta (Mr. Buchta)	J. Buchta
Energy Resources Conservation Board staff H. R. Hansford N. F. Lord	

2 ISSUES

The Board considers the issues with respect to the application to be

- need for the well,
- need for the well at a specific bottom-hole location,
- suitability of the proposed surface location.

3 NEED FOR THE WELL

Corexcal submitted that, as owner of a petroleum and natural gas lease issued by the Alberta Government, it had the right to explore for and recover the subsurface reserves it believed to be present in the drilling spacing unit comprising the southeast quarter of section 19. Corexcal stated three basic reasons why the well was justified. First, as holder of the mineral lease for the quarter section it had an economic need to develop the reserves it believed were present. Second, the drilling of the well would supply Corexcal with further geologic information which would allow it to test its geologic interpretation and better define the potential for further development in the region. Third, there was a contractual need for the well to be drilled to preserve Corexcal's right to the oil and gas lease.

The Rakettis did not dispute Corexcal's right to drill the well nor did they question Corexcal's need for the well. Their position was contingent, however, on the belief that this right should not interfere with the lives of other people.

The City stated that it did not dispute Corexcal's right to drill the well and its primary concerns centred around any adverse impacts which might result from production of the proposed well.

Mr. Buchta did not comment on any right to drill or the need for the well.

The Board accepts that Corexcal has the right to drill for such hydrocarbons which may underlie the drilling spacing unit since it holds the oil and gas lease. Furthermore, Corexcal has shown a need for the well to test its geologic information and to meet its contractual obligations. The Board, however, believes that these rights and needs must be weighed against any adverse environmental, safety, and social impacts which may result from drilling and producing the well.

4 NEED FOR THE WELL AT A SPECIFIC BOTTOM-HOLE LOCATION

Corexcal submitted that it had chosen the proposed subsurface location for the well based on its geologic and geophysical interpretation of the Nisku, the primary objective of the well. The applicant stated there was a possibility that the Leduc Formation might be a secondary objective; however, it did not believe the chance of an economic well in the Leduc Formation to be very high.

Based on its geologic interpretation of the area and data received from two seismic lines within the quarter section, Corexcal anticipated that it would encounter a Nisku structure of limited areal extent. The small area of the prospect made it imperative that Corexcal drill a conventional straight hole from its proposed surface location. It interpreted the prospective pool to be a Nisku structural high created by a thickening of Nisku porosity similar to other pools found in the Drumheller Field. The applicant expected the pool would be oil bearing, with gas in solution which could contain hydrogen sulphide (H_2S) of 2.95 per cent concentration and a corresponding calculated release rate of 0.00827 cubic metres per second. Corexcal believed the production capacity of a successful well would be in the order of only 8 cubic metres of oil per day and thus marginally economic.

Based on the restrictions imposed by the geologic nature of the pool and the marginal economics, Corexcal stated that any surface relocation of the well would increase the risk to a level which would not be acceptable. Movement of the well in a northerly direction would be undesirable as the well would encounter the Nisku porosity top at a lower structural level and hence increase the risk of encountering water. Moving to the northwest would place the well in an area of limited seismic information and increase the risk of missing the pool. Moving the well in a southerly or westerly direction was precluded as the well site bordered a steep escarpment above the Red Deer River Valley (see attached figure). Corexcal was reluctant to directionally drill the well from a more northern position, as suggested by the interveners, as this would greatly decrease the chance of hitting such a small geologic target. Moreover, the extra costs associated with directional drilling to recover the expected limited reserves would result in an economic return which Corexcal said would not justify drilling the well. Corexcal submitted that similar directional wells drilled in the area indicated that the cost of the well would be increased by as much as 160 thousand dollars.

The Rakettis, the City, and Mr. Buchta made no comments with respect to Corexcal's geologic and geophysical interpretation.

The Board has reviewed the applicant's geologic submission and finds Corexcal's geologic interpretation to be reasonable. It notes that there is limited well control and the interpretation and selection of a bottom-hole location have been based primarily on seismic interpretation. Given this, and the anticipated small size of the reservoir, the Board accepts Corexcal's desire to locate the well in the best possible location as defined by data from the nearest seismic lines.

The Board believes that directional drilling of the well is technically feasible. However, the risk of missing the expected pool, the additional costs, and the anticipated marginal economics of a directional well do not warrant directional drilling.

5 SUITABILITY OF THE PROPOSED SURFACE LOCATION

Corexcal submitted that it had no alternative for the surface location of the well and, as it had the support of the surface owner in locating the well as proposed, the applied-for location was appropriate. Corexcal stated that it would make every attempt to reduce any adverse impacts to the lowest possible level. To this end, Corexcal stated that if a successful well were completed it would locate production facilities on a separate lease to be situated approximately 300 metres north of the proposed well site. The well site would contain only a wellhead, pumpjack, and motor. According to Corexcal this would reduce the concerns of the Rakettis and the City respecting the visual impact of the well site. Corexcal also submitted that it would use a closed system to recover tank vapours at the production facilities and maintain a continuous flare, which should eliminate any production odour problems. If odour problems occurred from production of the well, Corexcal said it would react to complaints immediately and take whatever measures necessary to rectify any problems.

Corexcal was aware of the Rakettis' concern for their water well and stated that the procedures used in drilling and completing the Corexcal well should ensure that the water well was not damaged. If the Rakettis wished, Corexcal would test their water well for quantity and quality of water both before and after drilling, to ensure that no damage had occurred.

In order to address the concerns of the Rakettis respecting security of the well site, Corexcal stated that it would, after consultation with the surface owner, be prepared to fence the lease to ensure that entry would be restricted to authorized personnel. In summation, Corexcal stated that its policy was to try to accommodate all reasonable requests of landowners, and that it was also its policy to conduct any operation in a safe and responsible manner in accordance with good oil field practice. It was Corexcal's opinion that because of the measures it would undertake, the well should not have any negative impact on the Rakettis or on the City.

The Rakettis submitted that, even though measures such as the proposal for a remote production site would reduce some of the adverse impacts, they were still opposed to the drilling of the well. In their opinion, the well would have a negative impact on their life-style, for which, unlike the surface owner, they would receive no compensation. They had received no guarantee that such concerns as odours, noise, dust, security, safety, increased traffic, visual impact, and damage to their water supply would not occur as a result of the drilling and production of the proposed well.

The City stated that its primary concerns were the possible adverse visual and odour impacts on the Tyrrell Museum which could result from the well. The City stressed the importance of the Tyrrell Museum as a valuable tourist attraction in the area. The City stated that it was satisfied with the measures proposed by Corexcal provided that the measures were implemented and adhered to.

Mr. Buchta stated that as surface owner of the subject lands he was in support of the proposed location.

The Board believes that, based on the undertakings of Corexcal in response to the concerns outlined by the interveners, the surface location of the proposed well is acceptable. The Board agrees that the well and pumpjack would not likely be visible from the Tyrrell Museum. The Board accepts that levels of H_2S and subsequent odour problems should be low, given Corexcal's undertaking to use a closed vapour recovery system and an elevated flare with automatic ignition for production of the well.

The Board agrees that the proposal of a remote production facility is appropriate to reduce the visual impact and further notes Corexcal's undertaking to maintain both sites in a responsible manner.

The positioning of the battery to the north of the well site may be a source of occasional odours to the Rakettis; however, traffic past the Rakettis' home should not increase, given the location of the access road proposed by the applicant. The Board notes Corexcal's undertaking to fence the lease area to ensure security. The Board also believes it appropriate that Corexcal test the Rakettis' water well before and after drilling.

6 CONCLUSION

After reviewing the undertakings and commitments made by the applicant, the Board concludes that the well can proceed with minimum impact on the Rakettis and the Tyrrell Museum. However, due to the well's proximity to the Rakettis and the Tyrrell Museum, the Board will require that the following additional measures be implemented in addition to any other undertakings outlined by Corexcal:

- A closed tank vapour recovery system shall be utilized for the production testing of the well and for any permanent production facility.

- Adequate mufflers shall be employed during drilling operations to ensure that the Board's noise guidelines are met.

- The pumpjack shall be orientated in such a manner as to cause the least possible visual impact.

- A gate shall be constructed on the access road to the well site where it joins the municipal road, and shall be closed when no one is at the well site.

- The Board shall be advised in writing prior to commencement of drilling of the mitigative measures that have been and will be put in place.

7 DECISION

Having considered the evidence and viewed the proposed site, and taking into account the undertakings of the applicant and the additional measures which will be required, the Board is satisfied that the drilling of the well can proceed. Application 870077 is hereby approved, subject to Corexcal's undertakings and the conditions outlined above.

DATED at Calgary, Alberta, on 23 February 1987.

ENERGY RESOURCES CONSERVATION BOARD

Bohme

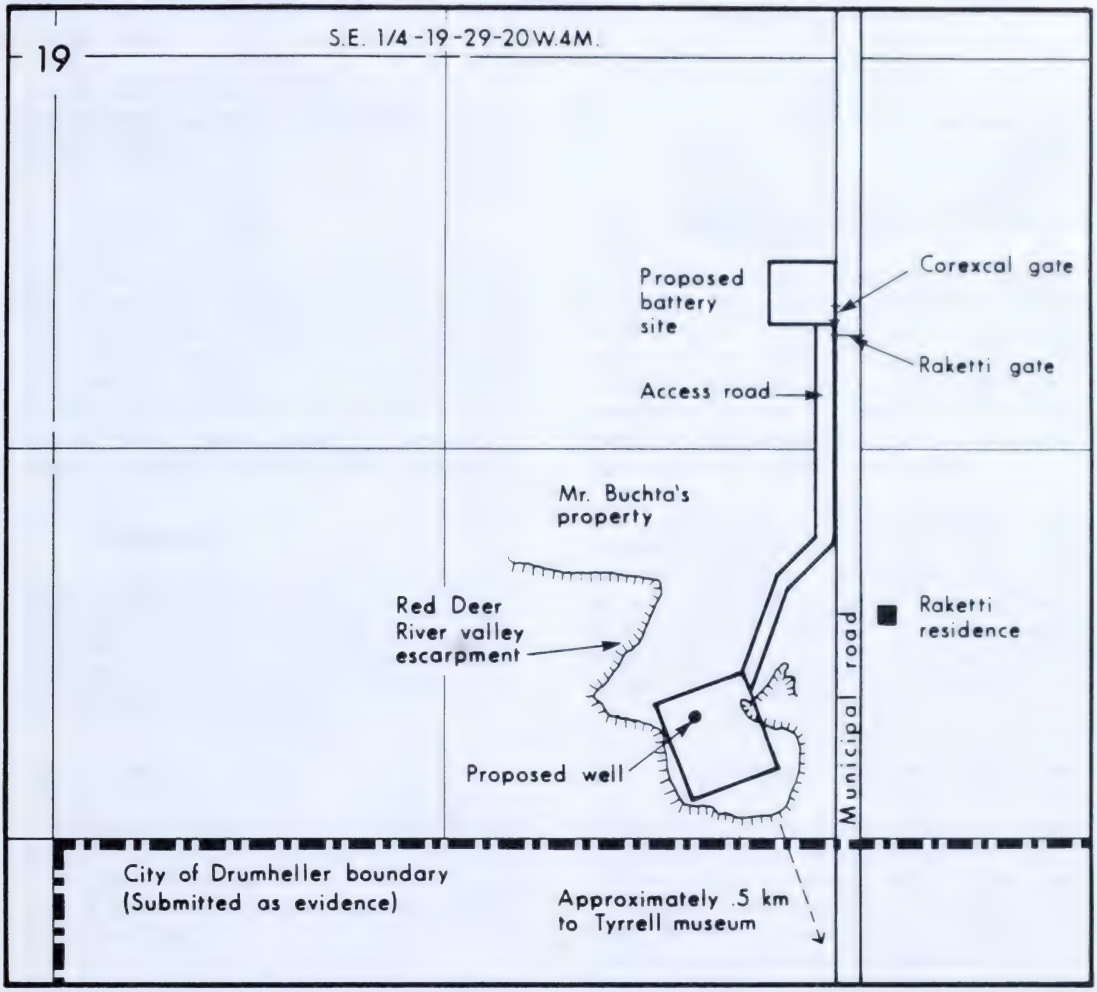
V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E. G. Fox

E. G. Fox, P.Eng.
Acting Board Member



COREXCAL WEST DRUMHELLER 1-19-29-20W.4M. PROPOSED WELL
Application No. 861641

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

G.N.E. RESOURCES LTD. REDUCED GAS WELL SPACING PREVO FIELD

Decision D 87-5
Application 860673

1 INTRODUCTION

G.N.E. Resources Ltd. applied under section 4.030 of the Oil and Gas Conservation Regulations (the Regulations) for an order prescribing drilling spacing units (DSUs) of one quarter section, with the target areas being legal subdivisions 6, 8, 14, or 16 as prescribed by Board Order SU 1088, for the production of gas from the Viking Formation in section 19 of township 39, range 1, west of the 5th meridian (W5M) (section 19).

1.2 Interventions

Gulf Canada Corporation submitted an intervention to the application. The legal firm of Macleod Dixon submitted an intervention on behalf of the mineral rights owners in the southwest quarter of section 19 but did not appear at the hearing.

1.3 Hearing

The application was considered at a public hearing on 17 February 1987, in Calgary, Alberta, by a division of the Board comprised of N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and Acting Board Member E. J. Morin, P.Eng.

Those who appeared at the hearing and abbreviations used in this report are listed in the table below.

1.4 Background

G.N.E. drilled the well in legal subdivision 8-19-39-1 W5M (the 8-19 well) in 1985 as a prospective oil well in accordance with normal oil DSUs of one quarter section. However, the well encountered only gas in the Viking Formation, for which the normal DSU is one section. The well was completed in the Viking Formation and produced at a rate of 32 thousand cubic metres (m^3) per day during testing.

G.N.E. is the lessee of the Viking gas rights in the southeast quarter of section 19. The mineral rights associated with the southwest quarter of the section are apparently not leased. In its intervention and at the hearing, Gulf claimed to be the lessee of the mineral rights in the north half of section 19, though that claim is apparently subject to litigation.

2 CONSIDERATION OF THE APPLICATION

G.N.E. presented data indicating that its 8-19 well encountered a very small gas pool which is about 4 hectares in area and contains 1 million (10^6) m^3 of gas. The applicant submitted that this small pool could extend into the adjacent section 20-19-1 W5M, but is not likely to extend into the southwest quarter or north half of section 19. G.N.E. noted that a number of other small Viking pools have been discovered in

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
G.N.E. Resources Ltd. (G.N.E.) J. K. Farries, P.Eng.	J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd.
Gulf Canada Corporation (Gulf) D. J. Gandar	R. M. Theberge, P.Geol. R. J. Meda, P.Eng.
Energy Resources Conservation Board staff H. R. Hansford K. Fisher M. Connelly	

the general area, and contended that the southwest quarter and north half of section 19 may contain Viking pools separate from the pool penetrated by the 8-19 well. The applicant argued that the establishment of one quarter section DSUs in section 19 would allow the mineral rights owners in other portions of section 19 the opportunity to explore for reserves which would not be recoverable through the 8-19 well. G.N.E. submitted that the establishment of one quarter section DSUs in section 19 would therefore be in accordance with section 4.030(3)(a) of the Regulations, and consistent with past decisions where the Board established reduced DSUs in circumstances similar to the case under consideration.

G.N.E. acknowledged that maintaining a one section DSU and pooling the mineral rights within section 19 was an alternative that would allow the 8-19 well to be placed on production. However, on the basis of its discussions with Gulf and the mineral rights owners in the north half of the section, the applicant was of the opinion that a voluntary pooling agreement was unlikely. It argued that applying under section 72 of the Oil and Gas Conservation Act (the Act) for forced pooling would be a cumbersome procedure involving additional expenses and delays which could not be justified considering the limited reserves associated with the 8-19 well. The applicant estimated that these reserves would generate only about $40 000 to $50 000 of revenue, which would not be sufficient to recover the costs of drilling the well, estimated at $250 000, and tie-in costs, estimated at $15 000 to $20 000. G.N.E. concluded that the establishment of reduced DSUs in section 19 represented an appropriate and practical method of obtaining production from the 8-19 well.

Gulf agreed that the Viking pool encountered by the 8-19 well contains about 1×10^6 m^3 of gas. However, it contended that, depending on the thickness and area geometry, the pool could be 8 hectares in area. Gulf presented a geological interpretation demonstrating that the pool is in a channel sand separate from nearby bar sand facies. It showed the pool to be an elongated reservoir trending north/south and possibly extending into the north half of section 19. Gulf argued that as the reservoir likely extends into the north half of the section, reserves underlying these lands would be drained by the 8-19 well. It considered pooling of the mineral rights in the section, rather than a reduction in DSU size, as the most appropriate means of equitable sharing of the gas reserves to be produced from the 8-19 well. In response to questioning, Gulf indicated that under a pooling arrangement in this case, it would be unlikely to make direct payments for its share of drilling costs, but instead would allow these costs, plus any penalties incurred, to be taken from its share of revenues obtained from producing the well. Gulf concluded that if negotiations for voluntary pooling failed, G.N.E. could apply under section 72 of the Act for forced pooling.

Finally, Gulf submitted that the application should be denied on its own merits because it does not meet any one of the four possible bases for approval set out in section 4.030(3) of the Regulations. Thus to grant the application would be an affront to the Regulations.

The Board recognizes an important issue in principle put forward by Gulf. That is that irrespective of how small a particular gas accumulation might be, in the absence of a clear fulfillment of section 4.030(3) of the Regulations, reduced gas well spacing should not be granted. Thus, even if several small gas accumulations were found in a given section of land, the appropriate mechanism according to Gulf would be to pool each of them among the owners in the section. In opposition to that position, G.N.E. argued that reservoirs should not be seen to fit the statutory one section gas DSU, but instead that DSUs should be modified when required to fit the size and shape of reservoirs.

The Board believes that these opposing positions must be considered in relation to the general objectives of the Act; namely sections 4(c) and (d):

> "4. The purposes of this Act are
>
> (c) to provide for the economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta,
>
> (d) to afford each owner the opportunity of obtaining his share of production of oil or gas from a pool."

The Board's view is that as a rule, where a natural gas reservoir extends over several sections of land or even a significant portion of a section, adherence to the one section DSU pooling approach best satisfies both sections 4(c) and (d) of the Act. However, where the areal extent is much less than one quarter section, reduction of the gas DSUs to one quarter section may better satisfy both sections 4(c) and (d). In the specific case of the 8-19 well, the accumulation is of such small extent (appearing to be less than one-tenth of a quarter section) there would seem to be little doubt that the latter course is most appropriate.

Gulf pointed out, that if the application were denied, G.N.E. could pursue either voluntary or forced pooling. However, in view of the extremely small size of the pool, it would appear that virtually nothing would be gained by a pooling arrangement since sales of the reserves are highly unlikely to pay for the sunk drilling costs, and indeed, may not provide for more than a marginal return on the tie-in costs yet to be incurred. From a practical viewpoint, therefore, pooling may only serve to impede or possibly completely discourage any efforts by G.N.E. to recover the small amount of gas reserves associated with the 8-19 well. Also, because of the small areal extent of the reservoir, the amount of drainage that could occur from the adjoining quarter sections is likely to be negligible. In view of all these factors, the Board considers pooling to be an unnecessarily complicated and impractical approach to obtaining production from the 8-19 well, whereas the establishment of reduced DSUs would represent an expeditious and administratively straightforward means of recovering the limited amount of gas recoverable from the 8-19 well. In this regard, the Board is satisfied that the application meets one of the requirements of section 4.030(3) of the Regulations, that of conservation by recovery of what would appear to otherwise be a forfeiture of reserves. Finally, the Board notes that there have been past cases where the Board has granted reduced DSUs which correlate more closely with the size of the reservoirs.

3 DECISION

The Board has decided to grant G.N.E.'s request to establish one quarter section DSUs for the production of gas from the Viking Formation in section 19-39-1 W5M as outlined in Application 860673.

DATED at Calgary, Alberta, on 27 February 1987.

ENERGY RESOURCES CONSERVATION BOARD

Strom

N. A. Strom, P.Eng.
Board Member

L A Bellows

L. A. Bellows, P.Eng.
Board Member

Morin

E. J. Morin, P.Eng.
Acting Board Member

JAN 27 [illegible]

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

NOTICE OF MOTION
Sulpetro Limited

Memorandum of Decision
Application No. 850272

1 BACKGROUND

Sulpetro Limited (Sulpetro) submitted Application No. 850272 dated 7 March 1985 for approval to implement design modifications at its Elmworth gas processing plant, to allow operation of the plant at an increased gas through-put rate and an increased ethane recovery efficiency.

After receiving a number of objections in response to notice of the application, the Board decided to consider the application at a public hearing scheduled for 27 January 1987.

In its intervention dated 13 January 1987, Alberta Gas Ethylene Company Ltd. (AGEC) included a report entitled "An Evaluation of the Issues Associated With Upstreaming in Alberta".

By letter dated 16 January 1987, Sulpetro moved to have Attachment III to AGEC's intervention and paragraph number 7 of the intervention which refers to Attachment III, struck out.

The Board subsequently scheduled a pre-hearing meeting on 20 January 1987, to discuss the motion.

Those who appeared at the meeting are shown on the attached table.

2 VIEWS OF THE PARTICIPANTS

Sulpetro's motion that the Board disallow paragraph 7 and Attachment III of AGEC's intervention was supported by Amoco, CHEL, Esso, and Scurry-Rainbow. The motion was opposed by AGEC, Dome and Dow et al.

Sulpetro and others in support of the motion argued that the subject material in AGEC's intervention deals broadly with issues of upstreaming which are not relevant to Sulpetro's proposed modifications now under consideration. Further, these parties noted that Sulpetro's plant was shown to be in the public interest and was approved by the Board in Decision 82-G after full consideration of the general issues.

The parties supporting Sulpetro's motion were also of the view that the subject material in AGEC's submission, if considered by the Board, could impact on much larger groups of both upstream and downstream interests than were going to participate at the hearing of Sulpetro's application.

AGEC and the others opposed to Sulpetro's motion argued that the subject material is relevant to the Board's consideration of Sulpetro's application and that the inclusion of this material complies with direction from the Board given in previous decisions on upstreaming that interveners address as extensively as possible the public interest issues.

AGEC also argued that the Board would have difficulty in determining the relevancy of the subject material to Sulpetro's application until evidence is presented at the hearing and that during the hearing and after, in reaching its decision, the Board would have the opportunity to consider the relevancy of any material.

3 BOARD'S VIEWS

The Board believes, on the basis of the arguments before it, that paragraph 7 and Attachment III of the AGEC intervention cannot be considered entirely irrelevant. However, the Board also believes that a portion of that evidence may be found to be irrelevant.

The purpose of the hearing scheduled for 27 January 1987 to consider Sulpetro's application is to hear evidence on the Part II application insofar as it differs from the Part I application as approved by the Board. Therefore, the Board will allow evidence from the AGEC intervention, including paragraph 7 and Attachment III, to the extent that AGEC demonstrates that its evidence is relevant to those changes. The Board anticipates there may be a need during the hearing for it to decide on the relevancy of evidence. It requests all parties to focus on the specific purpose of the hearing and thus restrict themselves to relevant evidence and argument.

The Board does not wish this proceeding to develop into a general inquiry relating to the upstream versus downstream ethane extraction issues. Interested parties may at some time request that such an inquiry be held as a separate proceeding. Alternatively, the Board, on its own motion, may decide at some future date to address those broad issues following due notice to all interested parties, either in conjunction with an application in which the primary extraction of ethane is a major part or as an independent general inquiry.

C. J. Goodman

C. J. Goodman

E. J. Mink

E. J. Morin
Acting Board Member

Those Who Appeared at the Meeting

Principals and Representatives

Sulpetro Limited (Sulpetro)
R. C. Muir

Alberta Gas Ethylene Company Ltd. (AGEC)
H. D. Williamson

Dome Petroleum Limited (Dome)
R. J. Hall

Dow Chemical Canada Inc.
Union Carbide Ethylene Oxide/Glycol Company, C.I.L. Inc.
Novacor Chemicals Inc. (Dow et al)
R. A. Neufeld

Canadian Hunter Exploration Ltd. (CHEL)
J. Mackie

Esso Resources Canada Limited (Esso)
D. G. Davies

Amoco Canada Petroleum Company Ltd. (Amoco)
D. G. Arnason

Gulf Canada Corporation
D. J. Gandar

Scurry-Rainbow Oil Limited (Scurry-Rainbow)
R. M. Perrin

Energy Resources Conservation Board staff
M. J. Bruni
B. C. Hubbard, P.Eng.

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SULPETRO LIMITED
INCREASED THROUGHPUT AND ETHANE RECOVERY
WAPITI GAS PROCESSING PLANT

Decision D 87-6
Application 850272

1 BACKGROUND

In March of 1982, Sulpetro Limited (Sulpetro) submitted a Part I[1] application for approval to extract ethane-plus (C_2+) from the natural gas processed at its Wapiti gas processing plant located in legal subdivision 4 of section 8, township 69, range 8, west of the 6th meridian. The application was considered at a public hearing in June 1982, and was subsequently approved.

In March of 1985, Sulpetro submitted a Part II application to the Board for approval to operate the new facilites. In its Part II application, Sulpetro brought to the Board's attention several design and operating changes made subsequent to its Part I application. These included a proposed increase in the maximum approved raw gas inlet rate from 9147 thousand cubic metres per day (10^3 m^3/d) to 10 028 x 10^3 m^3/d, an increase in the ethane recovery efficiency from 79 per cent to 88 per cent or greater, substitution of gas turbine drivers in place of electric drivers for residue gas compression, and addition of a de-ethanizer and an ethane condenser.

The Board considered the Part II design changes and recognized that they would impact the overall recovery of ethane upstream of the straddle plants. To avoid any undue effect on the parties involved while the changes were being reviewed, the Board granted approval to Sulpetro, by letter dated 6 August 1985, to operate its Wapiti deep-cut plant in accordance with the throughput and hydrocarbon recovery levels approved under its Part I application. At that time the Board also advised Sulpetro that final disposition of Application 850272 would depend upon response to notice of the application.

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[1] Applications under section 26, subsection (1), clause (b) of the Oil and Gas Conservation Act may be made in two parts as described in section 9.020, subsection (2) of the Regulations. The first part concerns the location, conservation levels, and pollution control features of the proposed scheme and is for approval to construct. The second part concerns other details of the scheme and is for approval to operate.

A number of objections were received and, in a letter dated 28 August 1985, the Board reaffirmed its approval for operation of the plant in accordance with the restrictions on maximum throughput and ethane recovery efficiency. However, in light of the objections raised, the Board required Sulpetro to file additional information to demonstrate that operation according to the Part II application would be in the Alberta public interest.

Upon receipt of the additional information in September 1986, the Board published a second notice to determine if any objections remained. Various objections were raised and the application was scheduled to be considered at a public hearing commencing on 27 January 1987.

A pre-hearing meeting was called on 20 January 1987 to discuss a motion by Sulpetro that certain portions of the Alberta Gas Ethylene Company Ltd. (AGEC) intervention be disallowed as evidence because it was alleged to be not specific to the subject application.

In its "Memorandum of Decision" issued on 21 January 1987, the Board ruled that it would consider AGEC's evidence so long as its relevancy to matters described in the notice of hearing could be demonstrated.

2 HEARING

The application was considered at a public hearing at the Board's offices in Calgary, Alberta, on 27 through 30 January, and 5 and 6 February 1987. The division of the Board appointed to hear the application consisted of C. J. Goodman, P.Eng. (hearing chairman), F. J. Mink, P.Eng., and E. J. Morin, P.Eng. The following table lists those who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Sulpetro Limited (Sulpetro) R. C. Muir	R. J. Zaharko, P.Eng. R. E. Cornies, P.Eng. G. M. Engbloom, P.Eng., of Confer Consulting Limited Dr. D. J. Hawkins, P.Eng., of Hycarb Engineering Limited

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Dow Chemical Canada Inc., Union Carbide Ethylene Oxide/Glycol Company, C-I-L Inc., Novacor Chemicals Ltd., and Celanese Canada Inc. (Dow et al) R. A. Neufeld	B. R. Wastle of Dow Chemical Canada Inc. Dr. T. R. Jones of Union Carbide Ethylene Oxide/Glycol Company G. Clarke of C-I-L Inc. D. J. Ferris, P.Eng., of Novacor Chemicals Ltd.
Alberta Gas Ethylene Company Ltd. (AGEC) H. D. Williamson	D. J. McConaghy D. F. Clarke, P.Eng. Dr. R. Mansell Dr. R. W. Wright both of Wright-Mansell Consulting Company G. W. Mathieson of Marenco Consulting Limited Dr. W. A. Langford of NOVA, AN ALBERTA CORPORATION
Amoco Canada Petroleum Company Ltd. (Amoco) D. G. Arnason	L. G. Cyca, P.Eng. R. B. Arnold, P.Eng.
Canadian Hunter Exploration Ltd. (CHEL) J. Mackie	
Dome Petroleum Limited (Dome) R. J. Hall	R.A.F. Evelein, P.Eng. D. G. Ramsden-Wood, P.Eng. R. C. Kettle, P.Eng.
Esso Resources Canada Limited (Esso) D. G. Hart, Q.C.	D. J. Henry D. D. Armstrong G. L. Barfoot, P.Eng.
Gulf Canada Corporation (Gulf) J. Caffrey	
Scurry-Rainbow Oil Limited (Scurry-Rainbow) R. M. Perrin	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board staff M. J. Bruni B. C. Hubbard, P.Eng. K. M. Johnston L. S. Fillion, C.E.T.	

CHEL, Gulf, and Scurry-Rainbow did not submit evidence and were present for the purpose of cross-examination and argument only.

Sulpetro's application was supported by Amoco, CHEL, Esso, Gulf, and Scurry-Rainbow. It was opposed by AGEC, Dow et al, and Dome.

3 DEFINITION OF THE ISSUES

As described in the Background section, Sulpetro made a number of design changes to the Wapiti plant after receiving its Part I approval but prior to submitting its Part II application for a licence to operate. These changes included the addition of a de-ethanizer and ethane condensing system, the use of gas drivers rather than electric for residue gas recompression, an increase in maximum gas throughput, and finally, the use of the patented Ortloff process to accommodate a higher than expected carbon dioxide content in the inlet gas and also to achieve a higher ethane recovery efficiency than conventional turbo-expander technology.

A major issue at the hearing was whether or not the changes identified in the Part II application are proper in the context of the original Part I approval of the plant.

A related issue is what impact the changes would have on the potentially affected parties and recognizing those impacts, whether or not the plant should be allowed to operate as installed.

4 DISCUSSION

4.1 Part I versus Part II Applications

After completing its 1985 review of Sulpetro's Part II application (which included Alberta Environment's review), the Board concluded that only the proposed increased throughput and ethane recovery efficiency had the potential to adversely affect any party. The Board therefore, on 6 August 1985, authorized Sulpetro to start up and operate the new plant at rates up to but not exceeding the maximum gas throughput rate and ethane recovery efficiency approved under its Part I application. In doing so, the Board clearly accepted the hardware modifications and additions made by Sulpetro as consistent with its approval of the Part I application.

With respect to the throughput difference between its Part I and Part II applications, Sulpetro stated that the requested increase in maximum gas throughput was necessary to accommodate increased nominations for capacity since the Part I design was approved. In addition, Sulpetro requested in the Part II application an increased ethane recovery efficiency so that it would be allowed to operate the installed deep-cut plant up to its maximum capability. The increased capability is a consequence of the installation of a different type of process than proposed in the Part I application. Sulpetro stated that it installed the Ortloff process because it could accommodate the higher than expected content of carbon dioxide present in the feed gas to the plant.

The interveners opposed to Sulpetro's application argued that Sulpetro had, without authorization, built a significantly different facility than had been originally approved and that this should not be condoned by the Board.

The Board is of the view that, aside from the sensitivity of the ethane upstreaming issue, there really are no extraordinary circumstances associated with the differences between Sulpetro's Part I and Part II applications. Part I applications are for the approval of a conceptualized scheme and the Board expects the design details to be reasonably represented. However, the Board also recognizes that at the time of a Part I application for a large plant, the final design details are not usually available. Following approval of a Part I application, the applicant typically optimizes its plant design within the general framework of the requirements of the ERCB and Alberta Environment. The Board therefore does not expect absolute adherence to every detail of a Part I application so long as resource conservation and environment protection are not jeopardized by reasonable changes made by the applicant.

The Board is satisfied that Sulpetro did not deliberately misrepresent its plant size in the original application and it was justified in increasing the capacity of the plant by 9 per cent to accommodate the larger nominations of throughput by users in the area. Also, the Board accepts that Sulpetro used sound engineering judgement aimed at solving a specific problem (higher than expected carbon dioxide content in the feed gas) in making its decision to install a different type of process technology. The Board concludes it is clearly the increased ethane recovery capability resulting from Sulpetro's change that is of significance rather than the change in the actual hardware itself.

The Board notes that the need for reconsideration of this application was largely due to the use of underestimated numbers for gas throughput and ethane recovery at the time the original application was submitted. To avoid recurrence of this problem, the Board requests future applicants for field facilities to identify the highest recovery level that could be expected and to provide the maximum anticipated throughput. The maximum figures would then be used to determine the maximum impact on other parties.

4.2 Impact of Installed Facilities

The Board gave notice of the application and received objections from the petrochemical industry and straddle plant operators confirming that they believed approval of the application would adversely affect them. After receiving the objections, the Board asked Sulpetro to submit additional information to address issues relating to the impact of the increased gas throughput and ethane recovery efficiency at the plant.

After reviewing the evidence, the Board concludes that while all public interest issues identified in earlier field plant applications continue to be relevant, only the potential market for incremental ethane and the economic implication on various affected parties are significant to its decision on this Part II application.

Sulpetro was of the view that its plant could recover additional ethane that would be incremental to the province and, notwithstanding the negative impact on the downstream sector, operation of the plant at its maximum capability would result in a positive net benefit to the province. It stated that the incremental recovery would have only a nominal negative impact on downstream interests. Sulpetro noted that its ethane is contracted to the enhanced oil recovery (EOR) market and the long-term supply/demand balance for ethane in Alberta shows an increased need for supply in EOR and the petrochemical industry.

Interveners opposed to the application argued that there is a provincial surplus of ethane supply over demand in the province and that incremental ethane produced at Wapiti would have no real value to the province. Further, Sulpetro's sale of the additional ethane from its plant to the EOR industry would merely displace a potential sale from another supply source already in place. Under this circumstance, operation of Sulpetro's plant at its potential would result in a net cost to the province. Although these interveners presented various cost/benefit analyses that showed net costs to the province associated with increased ethane recovery at Sulpetro's plant, they did acknowledge that, based on the cost data in Sulpetro's application, there would be a small public benefit if Sulpetro's plant operated up to its full potential when there was a shortage of ethane in the province.

The Board believes that any analysis of the impact of the Sulpetro plant, as installed, demonstrates that it would impose some negative impact on the downstream sector beyond what was originally perceived in

1982. The evidence suggests, however, and the Board agrees, that in this case whether the project represents a net cost or a net benefit to the province is to a degree dependent on the provincial ethane supply/demand balance. Considerable evidence was presented regarding ethane supply and demand and from it the Board concludes that some uncertainty exists, especially about the long-term picture. The evidence shows that in the past year the straddle plant system reinjected some surplus ethane into the gas stream leaving the province. While AGEC argued that there would likely be a long-term surplus of ethane, it noted that other market opportunities exist that could conceivably eliminate its surplus. At the same time it appears to the Board that field plants are able to sell all of their ethane production in the EOR market. The Board notes the evidence suggesting that ethane-plus liquids (rather than relatively pure or specification ethane produced by the straddle plants) is the preferred solvent material for miscible flood projects, but it also appears that AGEC and Dome are having some success in selling straddle plant ethane to the miscible flood market. Indeed, AGEC speculated that it would be able to capture a larger share of the miscible flood market in the future.

The Board is satisfied that increasing ethane demand in the EOR market and the petrochemical market will prevail in the future. Also, considering the evidence about the current extraction facilities, the Board does not accept that there will be a sustained provincial surplus of ethane throughout the life of the Wapiti facility. With this in mind, the Board concludes that market opportunities will continue to exist for ethane produced both at the existing field plants and at the straddle plants. Also, because of the relatively small volume of ethane at stake with Sulpetro's proposed increased recovery, approval or denial would not upset a balance by causing either a surplus or deficit situation and thereby affecting the market opportunities of other supply sources.

Given its conclusions regarding supply and demand for ethane in Alberta, and the results of cost/benefit analyses submitted by Sulpetro and the interveners opposed to the application, the Board believes that the additional ethane production from the Wapiti plant would provide a modest net benefit to the province and is therefore in the public interest.

With respect to the various cost/benefit analyses submitted, the Board accepts the cost data presented by Sulpetro as being a reasonable assessment of the changes in capital and operating costs attributable to the increased ethane production. Also, the Board believes that the methodology it has used in the past for assessing ethane upstreaming applications continues to be the most appropriate way to measure the effects on upstream and downstream interests and on the Alberta public interest.

5 DECISION

Having reviewed the relevant evidence, the Board is prepared to remove the conditions imposed 6 August 1985 restricting the maximum throughput and ethane recovery efficiency of Sulpetro's Wapiti plant. The Board will amend Sulpetro's approval to allow operation of the Wapiti plant up to a maximum raw gas inlet rate of 10 028 x 10^3 m^3/d with no restriction on ethane recovery efficiency.

DATED at Calgary, Alberta, on 2 April 1987.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman.

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

E. J. Morin, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DOME PETROLEUM LIMITED
PETRO-CANADA INC.
AMOCO CANADA PETROLEUM COMPANY LTD.
GAS CYCLING APPLICATIONS
BRAZEAU RIVER NISKU P POOL

Decision D 87-7
Applications 860891,
870055, and 870061

1 APPLICATIONS AND INTERVENTIONS

1.1 Dome

Dome Petroleum Limited (Dome) filed Application 860891 in July 1986 for approval of a full voidage replacement (FVR)[1] gas cycling scheme in the southern portion of the Brazeau River Nisku P Pool (the pool). Dome proposed an initial cycling rate of 281.7 x 10^3 m^3/d increasing to 507.1 x 10^3 m^3/d when plant expansion occurred. Injection would be into the 11-4-48-12 W5M well (11-4) and production would be from the 7-34-47-12 W5M well (7-34). Figure 1 shows Dome's applied-for "South" scheme area.

Between July and October 1986, Applications 861592, 861593, and 861594 were filed for construction of gas injection facilities needed for Dome's proposed cycling scheme. The Board approved these facilities on the understanding that Dome would bear the full risk of not being able to use the facilities if the applied-for cycling scheme were not approved. Subsequently, in October 1986, Amoco Canada Petroleum Company Ltd. (Amoco) filed Application 861505, pursuant to section 43 of the Energy Resources Conservation Act, for a review of the facilities applications.

A combined hearing was scheduled for 27 January 1987 to consider the Dome cycling application and the counter-application by Amoco to review the approvals of the gas injection facilities. Petro-Canada Inc. (Petro-Canada), Amoco, Texaco Canada Resources (Texaco), Columbia Gas Development of Canada Ltd. (Columbia), and D. M. Wolcott & Associates Ltd. (Wolcott) filed interventions to Dome's cycling Application 860891.

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[1] For the purpose of this decision report the terms full (100 per cent) voidage replacement and partial (60 per cent) voidage replacement are replaced by the abbreviated symbols FVR and PVR, respectively.

Prior to the hearing, Petro-Canada and Amoco filed their own applications for gas cycling in the pool (summarized below). As a result, the Board called a pre-hearing meeting on 22 January 1987 and decided to hear, on 2 March 1987, all the cycling applications and the Amoco application for a review of the Dome facilities.

1.2 Petro-Canada

Petro-Canada filed Application 870055 for a whole-pool FVR cycling scheme. The injectors for the whole-pool scheme would be 11-4, 9-7-48-12 W5M (9-7), 7-10-48-12 W5M (7-10), and 2-19-48-12 W5M (2-19). Petro-Canada stated that, if the Board were to approve Dome's South scheme, Petro-Canada would request approval for an "East" scheme and a "West" scheme, these being additional to the Dome scheme. The injectors for Petro-Canada's competitive schemes would be the same as those for the whole-pool scheme. Figure 1 shows Petro-Canada's applied-for scheme areas.

Dome, Amoco, Texaco, Columbia, and Wolcott intervened on the Petro-Canada application.

1.3 Amoco

Amoco filed Application 870061 for a whole-pool scheme, with an alternative "North" scheme for the remainder of the pool if the Dome "South" scheme were approved. At the commencement of the hearing, Amoco withdrew its whole-pool scheme and revised its "North" scheme to include an initial phase for sections 10, 11, and 12, with injection into 7-10 and production from 11-12-48-12 W5M (11-12)[2], and provision to expand the scheme, at some later date, to include the remainder of the North area. Amoco's first phase three-section scheme area is the same as Petro-Canada's East scheme area. Figure 1 shows Amoco's applied-for scheme areas.

Amoco's application was for a PVR scheme with injection of all residue gas. This would result in a voidage replacement of approximately 60 per cent.

Dome, Petro-Canada, Texaco, Columbia, and Wolcott intervened on the Amoco cycling application.

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[2] The 11-12 well (the Lodgepole Blowout well) has a surface location in 13-12 and therefore was referred to as the 13-12 well by some participants.

2 HEARING

A public hearing of the applications was held commencing 2 March 1987 with N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and J. A. Bray, P.Eng., sitting. Participants at the hearing are listed in Table 1.

At the opening of the hearing, Amoco withdrew its Application 861505 for a review of the approvals of Dome's gas injection facilities.

3 BACKGROUND

The Brazeau River Nisku P Pool was discovered in 1977 with the drilling of the Dome 7-34 well. The pool is located in the Brazeau River Nisku Carbonate Bank, and contains a rich, sour, highly retrograde gas having the potential for dry gas cycling. In-place reserves of raw gas are estimated by the applicants to range from 8283 x 10^6 m^3 to 9401 x 10^6 m^3. Figure 2 shows each applicant's interpretation of the zero pay boundary of the pool.

The 11-12 well blew out of control during drilling in late 1982 with the resultant loss of an estimated 3 per cent of the initial raw gas in place in the reservoir.

The pool currently contains eight productive wells whose capacities are estimated to range from approximately 150 x 10^3 m^3/d to 650 x 10^3 m^3/d. Six of the eight wells are currently tied into either the Petro-Canada Brazeau River gas plant at 4-31-48-12 W5M or the Dome-operated D. M. Wolcott West Pembina plant at 6-10-47-14 W5M. Pool production commenced to the Wolcott plant in June 1984 and to the Petro-Canada plant in August 1985. Figure 3 shows the wells, pipelines, and plant facilities in the area.

A Board inquiry concerning the optimum depletion method for the pool was completed in December 1984, resulting in ERCB Interim Decision D 84-30 and ERCB Decision D 85-10. The Board concluded, at that time, that the optimum depletion strategy was gas cycling with FVR above the dewpoint under a unitized scheme but that competitive primary production could occur down to a cycling operating pressure level of 28 800 kPa.

Negotiations to unitize the pool have been ongoing for some time, but as yet have not been successful. Primary production has continued to the point where the pool is approaching the Board-specified primary production reservoir pressure limit of 28 800 kPa and, hence, further primary production must soon cease.

4 APPLICANTS' AND INTERVENERS' GENERAL POSITIONS

4.1 Amoco

At the hearing, Amoco withdrew its whole-pool scheme in favour of its alternative competitive scheme proposal because it believed that formation of a single unit for the whole pool could not be achieved at this time. Amoco stated that it would support a Board decision to shut in the pool at the current time pending agreement amongst all parties for a whole-pool scheme, and requested that the pool be shut in after 2 years of cycling if a unit agreement for the North scheme, or the whole pool, were not in place.

Amoco supported PVR over FVR because of its higher economic return. Amoco indicated that if the fiscal regime were to change, conversion to FVR in the future would not decrease the ultimate recovery of liquids if the conversion occurred in the initial 2 years when the pool pressure remains above the dewpoint. In any case, Amoco was prepared to abide by a Board ruling which specified FVR.

Amoco proposed that the Board set additional conditions for competitive schemes, including initial rate limits set on the basis of current plant capacities of 280 x 10^3 m^3/d for the South scheme and 280 x 10^3 m^3/d for the combination of the East and West schemes, and then, after 2 years, rate limits set on the basis of reserves with a North/South split of 70/30, and also blowdown of all schemes to commence at the same time.

4.2 Petro-Canada

Petro-Canada preferred a whole-pool scheme because it would ensure optimum conservation while protecting equity and providing flexibility of operation. Petro-Canada stated that a whole-pool scheme would increase condensate recovery by some 6 per cent over competitive schemes. However, it proposed, as an alternative, multiple schemes in order to allow competitive operations to proceed if the Dome scheme were approved. The proposed East and West schemes excluded certain lands which Petro-Canada believed could not be easily unitized. Petro-Canada did not support Amoco's position to shut in the pool.

Petro-Canada submitted that gas cycling with FVR would be currently uneconomic, but it would seek royalty reductions that would make FVR economic. Nonetheless, Petro-Canada supported FVR in the short term because of the potential drawbacks involved in repressuring the pool. Petro-Canada proposed that, if royalty concessions were not granted, the pool would be blown down.

Petro-Canada indicated that rate limits were not initially needed for competitive schemes because current plant capacities would provide effective limits. After plant expansions took place, rate limits should be set on the basis of pore volume distribution, resulting in rates of 620 x 10^3 m^3/d for each of the East and West schemes, and 507 x 10^3 m^3/d for the South scheme. In addition, minimum pressures of 28 800 kPa and equal timing and rates of blowdown would be needed for all schemes.

4.3 Dome

Dome applied for its competitive scheme because of the lack of a unit agreement for the whole pool and to avoid the need to shut in production upon reaching the primary production reservoir pressure limit. It noted that the pool was composed of three partially separate reef build-up areas which would provide a degree of natural separation such that multiple competitive schemes, as proposed by the applicants, would not result in a lower recovery than a whole-pool scheme.

Dome supported FVR over PVR because the incremental volume of liquids obtained outweighed the apparent economic gain under PVR.

In Dome's view, the only conditions that needed to be imposed on multiple schemes were FVR and a minimum reservoir pressure of 28 800 kPa. It suggested that any further conditions should be handled, as and when warranted, by future applications.

4.4 Texaco

Texaco supported Petro-Canada's application because a whole-pool scheme would optimize liquid recovery, and the competitive West scheme would allow Texaco its only opportunity to recover its fair share of pool reserves on a timely basis.

4.5 Columbia

Columbia said that a whole-pool scheme with FVR would provide the optimum recovery from the pool. However, because of the difficulty in achieving one unit for the whole pool, two or more schemes would be required. Columbia supported Dome's application.

4.6 Wolcott

Wolcott requested that the Board not approve a scheme which would result in a temporary or permanent reduction in the rate of raw gas to supply to its plant.

5 ISSUES

The Board recognizes that it had reached the view in Decision D 85-10 that pool-wide unitization is required for cycling to proceed in an efficient manner. As well, the Board observes the continuing unanimous view of all parties that a whole-pool cycling scheme would be desirable, but that there are continuing difficulties in reaching a pool-wide unit agreement.

The Board, now faced with applications for competitive schemes, must decide if the net advantages of a single pool-wide scheme outweigh the net advantages of competitive schemes. If competitive schemes were to be approved, it must then decide what special efforts and conditions should be applied to minimize the disadvantages of competitive schemes.

These issues are addressed in the following section.

6 BOARD'S CONCLUSIONS

6.1 Whole-pool Versus Multiple Competitive Schemes

The Board believes that, over the long term, the major advantage of a whole-pool scheme would be flexibility to adjust injection and production strategy to promote maximum sweep and recovery of reservoir hydrocarbons. However, a whole-pool scheme could not proceed without unitization or equivalent operating agreements, and it appears that this would necessitate shutting in the pool until the necessary agreements are signed. This would likely impose an economic penalty on all owners and does not appear to fulfill the general objective of economic, orderly, and efficient development of the province's oil and gas resources. In conclusion, the Board would not be inclined to withhold approval of the competitive schemes unless recovery from the pool would be materially reduced by the operation of such schemes.

The Board notes that all applicants concluded that allowing competitive operations to proceed now would have both economic and environmental advantages with full utilization of currently available plant capacity. As well, until expanded plant process capacity becomes available, withdrawals would occur at relatively low rates and would allow for further reservoir definition and negotiations for a whole-pool unit.

The Board considers that a favourable sign for the potential future amalgamation of the competitive schemes into a whole-pool scheme is that the proposed initial injection locations for the competitive schemes would be the same as those for a whole-pool scheme. Also, in this regard, the Board believes that the operators should avoid making any commitments (eg. make-up gas supply) in a manner which might seriously hinder future amalgamation of the competitive schemes.

If, over the long term, amalgamation of competitive schemes were not to occur, potential recovery loss could be avoided by ensuring FVR and fully effective pressure maintenance within each scheme, and by closely monitoring effects of one scheme on another and taking corrective action if needed.

In conclusion, the Board would be prepared to approve the competitive schemes for the lands applied for as outlined below:

Scheme	Applicant (Application No.)	Scheme Area	Injector	Producer
South	Dome (860891)	Sections 27, 33, 34, 35 of 47-12 W5M & Sections 3, 4, 5 of 48-12 W5M	11-4	7-34
East	Amoco (870061)	Sections 10, 11, 12 of 48-12 W5M	7-10	11-12
West	Petro-Canada (870055)	Sections 7, 8, 17, 19, 20 of 48-12 W5M	9-7	2-19 3-20

The Board notes that, in some cases, the applicant for a particular scheme did not have agreement of all the working interest owners in the included lands. While some evidence was presented at the hearing regarding the status of negotiations among the parties, interpretation of agreements is not within the Board's jurisdiction. However, the Board would expect that agreement would be reached among working interest owners in each approved scheme prior to cycling.

Also, the Board notes that there are potentially productive lands within the pool limits but outside the applied-for scheme areas. Should the operators choose to continue with their competitive schemes option, then lands outside the scheme areas will need to be established as productive by either the drilling of wells or by agreement as a pre-condition to inclusion into either a previously approved or a new cycling scheme approval.

The Board, in wanting to ensure conservation and the protection of equity, would expect these schemes to proceed in approximately the same time frame. If such were not to occur, the Board recognizes that it may need to take corrective measures.

6.2 Operating Conditions and Limits

6.2.1 Voidage Replacement Ratio

The Board notes that most of the retrograde condensation would occur during a modest pressure decline below the dewpoint. The Board believes that revaporization of condensed liquid, which would accumulate in the reservoir as a result of the declining reservoir pressure under PVR operations, would be dependent on the injected dry gas dispersing effectively throughout the reservoir pore system, and intimately contacting those liquids. The Board's view is that there is considerable question as to the degree to which this would occur. As a result, initial operation under PVR would introduce an inappropriate risk of conservation loss. Therefore, for any cycling scheme approved at this time, the Board would require FVR.

6.2.2 Reservoir Pressure

The Board believes that conservation would best be served by requiring that all areas within a scheme be continuously maintained at a pressure level above 28 800 kPa. For example, if a permeability restriction were to retard effective pressure support to a producing well, then the production of that well would have to be curtailed or injection relocated to prevent creation of a pressure sink and resulting recovery losses from occurring. This kind of action would, at the same time, reduce the possibility of inequitable depletion of a neighbouring scheme.

The Board believes that an appropriate program of reservoir pressure monitoring would be for each producer to be surveyed semi-annually and each injector annually, with pressures extrapolated to stablilized conditions after a minimum 2-week build-up or fall-off period. Preferably, pressure surveys would be conducted when the whole pool is shut in. The Board believes that an appropriate time for one of the semi-annual surveys would be during plant turnaround, and would encourage the operators to co-ordinate their efforts in this regard. Also, the Board would require that the results of each pressure survey be provided immediately to the operators of the other schemes in the pool.

6.2.3 Drilling Additional Wells

The Board's view is that the drilling of additional wells in the pool would tend to improve the opportunities for increased recovery. However, the Board cautions that the production or injection at any well would be subject to potential restrictions either to improve hydrocarbon recovery or to maintain equity in a continuing competitive scheme situation.

6.2.4 Cycling Rates

The Board notes that all applicants agreed that the currently available plant processing capacities would serve to adequately control rate of cycling in the initial years until plant capacities are expanded. Although the Board would not see an absolute need to specify rate limits for these initial years, it would, nevertheless, specify rate limits as a precautionary measure. For the South scheme and the combination of the East and West schemes, these initial rates would be equivalent to the respective available plant capacities. If other rate limits were deemed to be necessary at some future time, the Board would consider the matter in light of the then existing circumstances.

6.2.5 Performance Reports and Information Exchange

The Board believes that full and timely scheme-performance reports, made available to operators of other schemes, would provide a sound basis for inter-scheme co-operation. In addition to the normal reporting of a scheme's performance, the inclusion of future production/injection schedules and operating plans would allow each operator the opportunity to assess the plans of the other operators. Semi-annual reports submitted within 2 months after each 6-month performance report period and routinely exchanged between scheme operators for the first 2 years of cycling operations would seem appropriate. After 2 years, the Board would review the frequency of reporting requirements.

To facilitate communications, the Board would be prepared to convene meetings to discuss the performance/forecast reports immediately after they are made available and, if necessary, direct any special measures to protect conservation and equity.

7 DECISION

1. The Board has decided to grant approvals to the applicants for the three cycling schemes as follows:

Scheme	Applicant (Application No.)	Scheme Area	Injector	Producer
South	Dome (860891)	Sections 27, 33, 34, 35 of 47-12 W5M & Sections 3, 4, 5 of 48-12 W5M	11-4	7-34
East	Amoco (870061)	Sections 10, 11, 12 of 48-12 W5M	7-10	11-12
West	Petro-Canada (870055)	Sections 7, 8, 17, 19, 20 of 48-12 W5M	9-7	2-19 3-20

2. Each scheme will be subject to the following conditions:

   (a) Full voidage replacement.

   (b) Reservoir pressures maintained at or above 28 800 kPa throughout the scheme area.

   (c) Production rates of the Dome South scheme limited to a semi-annual average of 280 x 10^3 m^3/d, and the combined rate of the Amoco East scheme and Petro-Canada West scheme limited to a semi-annual average of 280 x 10^3 m^3/d.

   (d) All scheme performance information and operating forecasts made promptly available to the operators of other schemes in the pool.

DATED at Calgary, Alberta, on 10 April 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

Bellows

L. A. Bellows, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) S. E. Lipton	R. Nicholls, P.Eng. J. D. Griffith, P.Eng. R. Dreveny, P.Eng.
Petro-Canada Inc. (Petro-Canada) W. J. Hope-Ross	G. A. Reitzel, P.Eng. A. Agate, C.E.T.
Dome Petroleum Limited (Dome) F. M. Saville, Q.C. R. A. Neufield	J. R. Moore, P.Eng. G. Besserer, Ph.D, P.Eng. G. Buchanan, P.Geol. B. Wood, P.Eng.
Columbia Gas Development of Canada Ltd. (Columbia) D. G. Guest	
Texaco Canada Resources (Texaco) G. J. Choate	
D. M. Wolcott & Associates Ltd. (Wolcott) H. R. Ward	F. Remtulla, P.Eng.
Energy Resources Conservation Board staff H. R. Keushnig, P.Eng. N. R. Runciman, P.Eng. A. A. Broughton N. Nastasa R. M. Feick	

NOVA, AN ALBERTA CORPORATION, as applicant on Application 861593, did not appear at the hearing. Amoco withdrew its Application 861505 to review Application 861593 at the outset of the hearing.

Columbia and Texaco participated in the hearing for the purposes of cross-examination and argument only, and did not present any direct evidence.

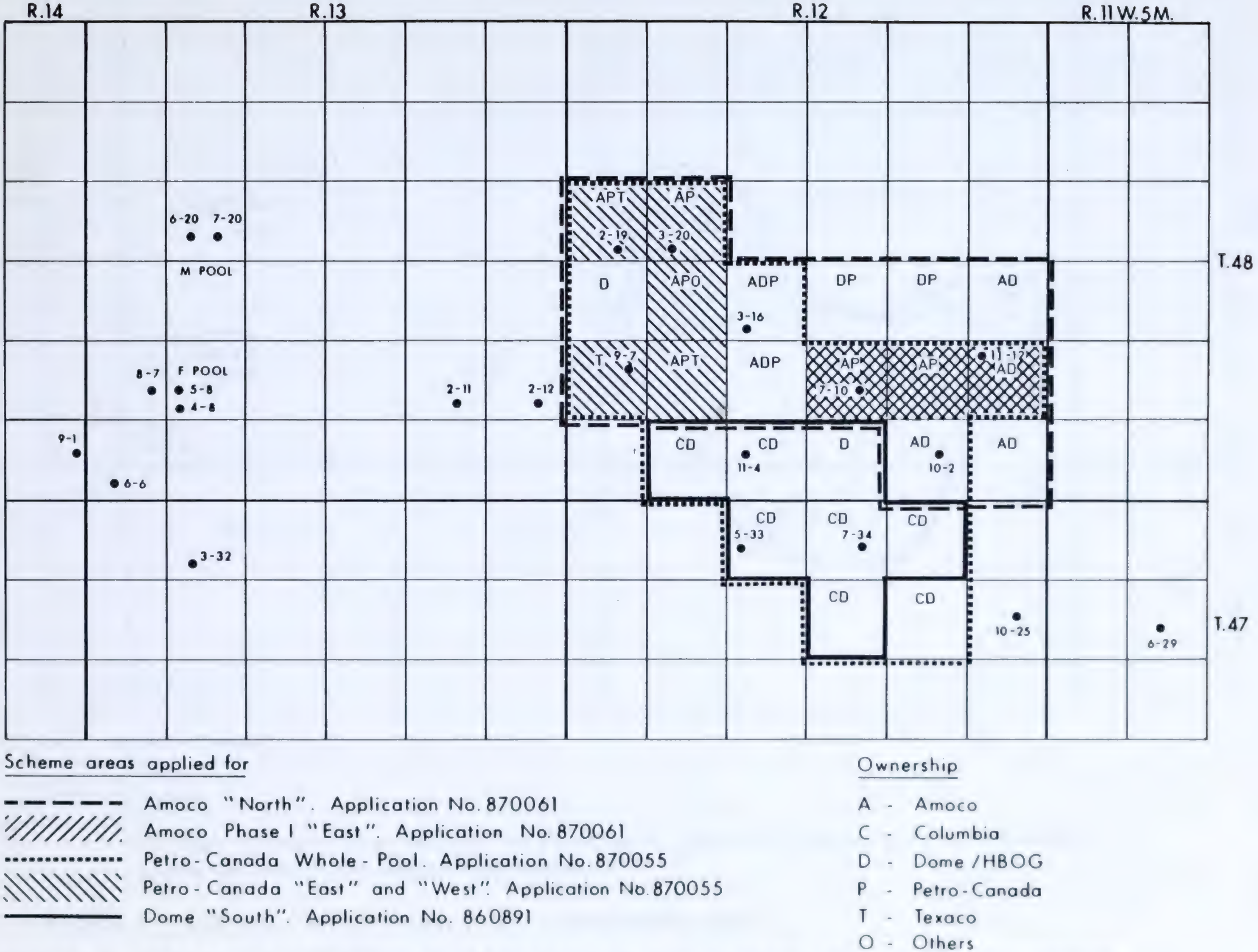
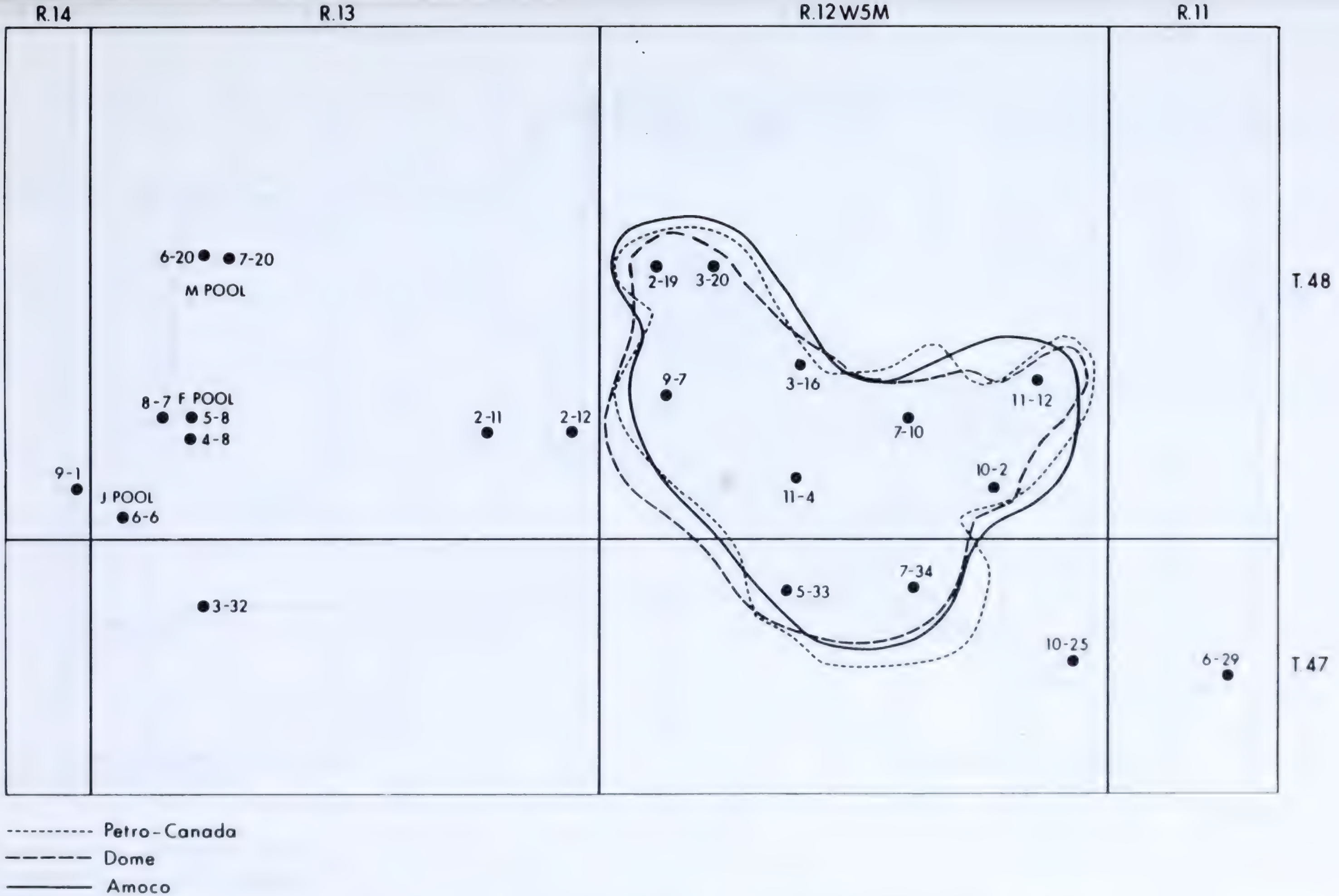


FIGURE 1 BRAZEAU RIVER NISKU P POOL APPLIED FOR SCHEME AREAS AND OWNERSHIP



This figure represents approximate zero pay boundaries for comparative purposes and it is not intended as a precise statement of the operators' interpretations.

FIGURE 2 BRAZEAU RIVER NISKU P POOL INTERPRETATIONS

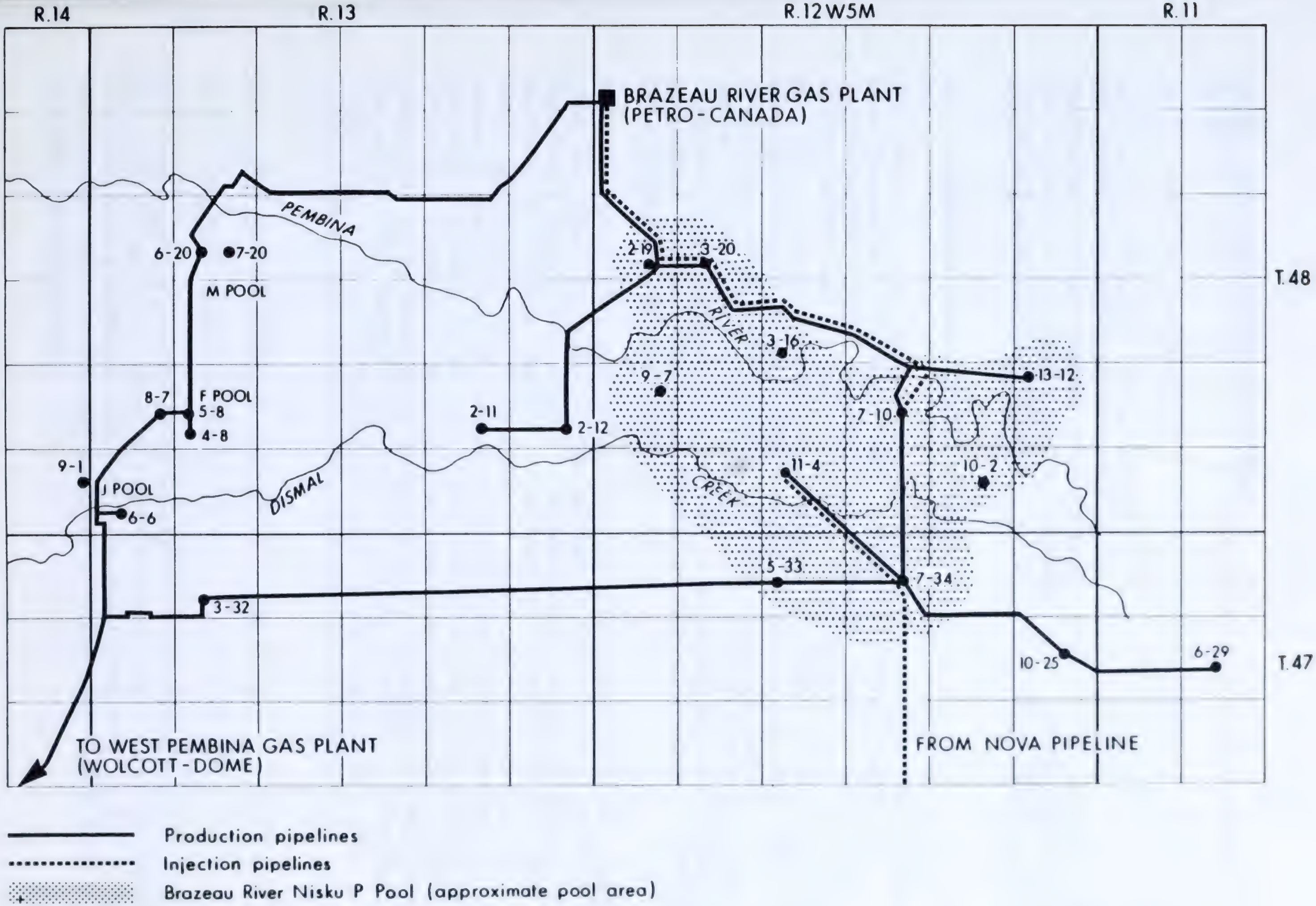


FIGURE 3 BRAZEAU RIVER NISKU P POOL AREA GAS PROCESSING AND GATHERING FACILITIES

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY SHELL CANADA LIMITED FOR APPROVAL OF THE TRANSPORTATION AND PROCESSING OF HIGH HYDROGEN SULPHIDE SOUR GAS RESERVES IN THE CAROLINE FIELD AND AREA (BEARBERRY DEMONSTRATION PROJECT)

Decision D 87-8
Applications 861525, 870045, 870046, & 870047

1 BEARBERRY DEMONSTRATION PROJECT

The reserves of the Devonian Leduc reef in the Caroline Field and Area were discovered in the late 1960s. The Shell Cdn-Sup Bearberry 12-21-33-6 W5M (12-21) and Mobil G.P.D. Banner James 11-35-33-7 W5M (11-35) wells were drilled in 1969 and 1970, respectively. The 12-21 well was production tested for 6 weeks in September and October 1969 and showed a hydrogen sulphide (H_2S) content in the gas of about 90.0 per cent. Drill stem tests on the 11-35 well indicated similar concentrations of H_2S. Shell Canada Limited (Shell) estimates that reserves in the area could be as much as 70 to 100 million tonnes of equivalent sulphur, with about 15 million tonnes of sulphur in place in the vicinity of the 12-21 and 11-35 wells.

Shell indicated that current data on reservoir phase behaviour suggests that only about one-third of the sulphur in the reservoir could be recovered; hence, the need for a demonstration project to determine if improved recovery is possible. The Bearberry demonstration project would last 5 years and be designed to establish the technical and economic feasibility of commercial development of the resource. Thus, the sour gas plant to be used in the demonstration project would consist of modular components that could be dismantled and removed. Future commercial development plans would therefore depend on the results of the applied-for demonstration project and any proposal to construct large-scale, long-term facilities would be the subject of a new application for consideration by government and the public.

2 THE APPLICATIONS

2.1 Integration of Facilities

The demonstration project would consist of two producing wells, a sour gas plant primarily to produce liquid sulphur, and connecting pipelines for controlling downhole well producing conditions and for moving high H_2S content fluid up the well production string, and thence from the wellheads to the plant.

2.2 Pipelines

Shell submitted applications for approval to construct pipelines connecting the production wells to a gas plant proposed to be located at S 1/2-5-34-6 W5M. The production pipelines and related facilities would be designed to transport multi-phase effluent from the 11-35 and 12-21 producing wells to the processing facility. These pipelines would be designed to transport well effluent with a maximum H_2S content of 90.4 per cent (904 mole per kilomole). Additionally, high pressure oil circulation pipelines and related facilities would transport light oil from the proposed gas plant back to the two producing wells. Fuel gas pipelines and related facilities would be built to transport sweet fuel gas from a meter station in Lsd 4-5-34-6 W5M to the wells and to the gas processing unit.

2.3 Sour Gas Plant

The applied-for gas plant would be designed to process high concentration H_2S well effluent for the purpose of recovering sulphur. The proposed facility using a 4-stage sulphur plant with a sub-dewpoint conversion process would achieve a minimum of 98.0 per cent annual sulphur recovery efficiency and would produce a maximum of 204 tonnes per day (t/d) of liquid sulphur which would be trucked out of the area to markets. A maximum of 8.3 t/d of sulphur dioxide (4.2 t/d of sulphur equivalent) would be emitted to the atmosphere through a 57.0-metre incinerator stack designed to meet Alberta Environment Air Quality Standards.

2.4 Emergency Response Plans

An emergency response plan for the integrated facilities, including wells, pipelines, and gas plant would be submitted at a later date and would require Board approval prior to Shell receiving any licence to operate the facilities. The public would be given opportunity for input to the emergency response plan during its development.

3 THE HEARING

The applications were considered by the Board at a public hearing in Sundre, on 18 March 1987, with N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and Acting Board Member E. G. Fox, P.Eng., sitting. Those who appeared at the hearing and the abbreviations used in this report are listed below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) D. O. Sabey, Q.C.	G. W. Stephens, P.Eng. W. R. Grieef, P.Eng. H. J. Lyon, P.Eng. P. Kitzan, P.Eng. J.W.F. Klein, P.Eng. D. Atwell, P.Eng. C. A. Bonke B. J. Griffin, P.Eng. of Bercha Alberta Ltd. D. M. Leahey of Western Research, Divison of Bow Valley Resources Services Ltd.
L. Bauman J. Bauman	L. Bauman J. Bauman
C. Newsham	C. Newsham
Alberta Environment R. L. Stone	
Energy Resources Conservation Board staff C.J.C. Page E. P. Moeller, R.E.T. A. Cassley, P.Eng. D. G. Beamer	

Written interventions to the application were received from Louis and Joseph Bauman, and Cyril Newsham an area resident. At the opening of the hearing, Dr. Joseph Bauman presented an opening statement and questioned the completeness of the application. Similarly, Mr. R. McIntyre, the Mayor of Sundre, presented an opening statement supporting Shell's application but identifying potential concerns about products trucking. Mr. Newsham gave evidence about safety, road conditions, traffic, health, and impacts on wildlife in the area. Additionally, a number of other individuals spoke at the hearing. Mr. R. Alberda stated that he is concerned about emissions of sulphur and Shell's future plans for the project. Mrs. M. Goodwin voiced concerns about heavy truck traffic and development in the area. Ms. J. McDiarmid expressed concerns about truck traffic and plant sulphur emissions. Mr. M. Davis of the Alberta Forest Service questioned Shell's plans to tie in other wells to the proposed plant from the James River area.

4 ISSUES AND CONCERNS

The Board notes that the main concerns about the project raised at the hearing related to traffic safety and environmental protection. Safety matters primarily focused on concerns about truck traffic routes, road use, and road crossings during construction and operation of the facilities. Environmental concerns related to plant emissions, human health, and disturbance of wildlife. Offsetting these concerns were a general desire to promote local employment and use of local services, and generate local economic benefits that would enhance community life-styles.

The Board considers the main issues to be

- general suitability of the integrated facilities for the purpose of conducting the demonstration project,
- pipelines design features,
- plant design for stability and safety,
- plant emissions and monitoring,
- truck traffic during construction and products truck traffic during operations,
- other environmental impacts, and
- communications with local residents and towns.

5 ISSUES AND CONCERNS

5.1 Integrated Facilities

Shell

Shell outlined its project to include two existing wells, field facilities and gathering system, the processing plant and sulphur recovery unit, and a description of associated off-site facilities. It pointed out that the plant site was chosen after extensive consultation with local residents and was aimed at minimized impact. The two wells that will supply the plant will provide opportunity to test variable conditions at the wells, the pipelines, and the plant. Warm refined oil will be circulated at high pressure down the tubing annulus and will mix with sour gas as it flows up the tubing. By this procedure Shell expects the production rate of entrained sour gas will be subject to a high degree of rate and pressure control.

Board

The Board is generally satisfied that the design of the facilities and especially the ability to control reservoir fluid inflow by pressure and rate control of the circulated oil provides unique advantages for safe operation.

5.2 Pipelines

Shell

Shell stated that the pipelines would meet or exceed the design requirements of the current Canadian pipeline standards. A number of safety features are incorporated into the design, including an emergency shut-down (ESD) valve at each end of the oil circulating line and the production line. The operating pressure on the production line would result in a very low stress level in the pipe material. Initial start-up pressures would be higher but still well within design limitations. In the matter of leak detection, Shell indicated that it would have H_2S detectors at the well sites and would conduct an annual leak survey using electronic equipment. Any severe loss in pipeline pressure would result in the automatic closure of the ESD valves. Shell expressed its intention to augment these methods with acoustic monitoring.

Shell outlined its corrosion monitoring program which would include the monitoring of corrosion coupons, ultrasonic inspection of the pipe at selected locations, and regular internal electromagnetic inspection of the production line. Initially, electromagnetic inspections would be carried out at intervals of 3 to 6 months.

None of the interveners questioned the design of the pipeline.

Board

The Board is generally satisfied with the design of the pipelines, but has concerns with two features. The first is the use of ESD valves on the pipelines; the concern being the effect of rapid closing of the valves on the pressure transients in the pipelines (the "water-hammer" effect). The second concerns the overpressure protection of the production pipeline from the very high pressure in the oil circulating system which is separated from it by a choke yet to be selected. The Board would require that these be satisfactorily addressed before it would grant permits for construction. As well, the Board would require that water-hammer effect calculations and any necessary mitigating design features on the oil circulating line, and details of the protection devices for the production line be submitted to it for review. The Board will not require the use of the acoustic monitoring technique. However, the Board is interested in the development of this technique and will direct its staff to follow up with Shell on its use.

5.3 Plant Design for Stability and Safety

Shell

Shell stated that as a matter of necessity it had to design its plant facilities with stable operations and safety in mind. It explained that much of the plant incorporated demonstrated and proven technology and all vessels in the plant are designed for sour service conditions. In order to accommodate well effluent and for safety reasons, Shell said it designed the plant inlet separators to handle more than three times the maximum flow rates of the inlet pipelines in order to prevent possible overflow and upset conditions in the gas plant. Additionally, the process includes a surge drum to accommodate any carryover of liquid hydrocarbons and an overflow vessel as back-up to catch any liquid carryover that might occur. It stated that the inlet separators will be inspected every 3 to 6 months initially and inspected on a regular frequency after reviewing test results. Shell said it expects corrosion of vessels to be minimum and it would conduct ultrasonic tests and use corrosion coupons to test integrity of vessels. It stated that corrosion inhibitors would be used in the pipelines and various plant process vessels to minimize corrosion. Fire detectors would also be provided and these detectors would be linked to the alarm display system at the gas plant which is manned 24 hours per day.

Board

The Board believes that the general design concepts including surplus inlet surge capacity should result in stable and safe operations.

5.4 Plant Emissions and Monitoring

Shell

Shell stated that environmental planning has been a major consideration in the project design in order to protect land surface, water resources, and air quality. It described how the project has been designed and will be built and operated in a manner that will ensure it does not cause significant environmental damage.

The applicant said it chose the established MCRC[1] sulphur recovery process that would ensure recovery of not less than 98.0 per cent annually of the equivalent sulphur produced to the plant. It stated that the sulphur plant with a turndown level of 3:1 would ensure control for potential fluctuations or swings of H_2S volume and flow rate without causing plant upsets. Shell indicated that actual sulphur recovery levels could be 0.5 per cent higher during plant operations. Additionally, it stated that the sulphur recovery unit is going to be designed to accommodate up to 6.0 per cent gaseous hydrocarbons which the applicant said is about double what it anticipates as being normal.

To monitor potential environmental effects, Shell stated that it will install a network of sulphation and H_2S cylinders in the area. It said it would also monitor soils and analyse them for selenium levels and buffering capacities, although Shell stated that it believes the emissions from the plant will have no significant effect on the selenium levels in the area. Additionally, with respect to the possibility of heavy metals emissions from the plant, Shell stated that it has no evidence that heavy metals exist and that testing on its other existing plants has shown no identifiable problem. During plant operations Shell explained that it will have stationary continuous air quality monitors in the area and will conduct mobile air quality monitoring surveys to test ambient air during plant start-up.

Regarding potential odour effects, the applicant described how the plant facilities, including those for liquid sulphur storage will be carefully designed to minimize fugitive emissions. It stated all safety valves and other equipment that could be used to release H_2S under normal operating conditions will be connected to an incinerator stack. Additionally, the applicant affirmed that in order to prevent odours, liquid sulphur will be degassed prior to storage and shipping by truck. Shell stated that plant flaring will be kept to a minimum and noise should not be a problem because of the type of equipment used in the plant process. In order to prevent site contamination, Shell stated that all its building floors will be paved and any contaminated fluids or spillages will be directed to a holding location for clean-up. It said any type of spill will be documented as to where and the type of material spilled. Shell stated that solid wastes from the facility would be sent to an approved landfill site.

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[1] MCRC (Mineral and Chemical Resource Company). The MCRC process is a variation of the Modified Claus process wherein H_2S and SO_2 are reacted catalytically at temperatures below the dewpoint of the produced sulphur vapour.

Interveners

All of the interveners and other individuals who spoke at the hearing expressed concerns about potential plant sulphur emissions and their desire to see best available technology tested. They asked that Shell recover as much sulphur as possible to reduce any environmental impacts caused by sulphur emissions. Mr. L. Bauman questioned whether there is any possibility of heavy metals occurring in the production reservoir.

Board

The Board notes that the plant will utilize established sulphur recovery technology and is designed to minimize or preclude emission problems. Although the ERCB sulphur recovery guidelines require a minimum recovery of 97.7 per cent of the inlet sulphur on a quarterly basis, the Board understands that the actual recovery rate should normally be somewhat higher on an annual basis. The Board finds that the applied-for sulphur recovery efficiency level is appropriate for the proposed plant. Regarding the matter of heavy metals, the Board is aware of tests for heavy metals in sour gas plant emissions in the province and will review the need for such tests on the proposed plant.

6 TRAFFIC

Applicant

Shell responded to questions on traffic by describing Shell's driver training programs and routing of vehicles. Shell agreed to investigate a suggestion by Mrs. Goodwin to route traffic along alternative roads to minimize chances of conflict between local traffic and trucking during plant construction and operation. In response to Mr. Newsham's concerns about traffic and animals in the area, Shell said its vehicles could be equipped with ultrasonic horns to prevent animal and vehicle accidents. Shell said that during construction of the demonstration project, there will be an increase in traffic along the existing paved road west from Highway 22X but that with the exception of occasional heavy or slow loads this should not significantly affect normal traffic flow. It said that after construction, shift changes and other personnel and equipment movement will continue to generate some traffic. Truck movement is estimated at 15 vehicles per day.

Interveners

Mrs. Goodwin said she was concerned with trucks hauling chemical and solvents in the area and worried about Shell's longer term development plans. Mr. McIntyre cautioned that the town of Sundre is on a route for hauling hazardous goods. Mr. Newsham expressed concerns about traffic safety, road deterioration, vehicles exceeding speed limits, and impacts of vehicles on wildlife. Ms. McDiarmid supported Mr. Newsham's views on traffic concerns.

Board

The Board acknowledges that whenever development takes place an increase in traffic usually results. The Board also recognizes the concerns of the public regarding hazards of increased traffic particularly in a rural area. The Board accepts that Shell will establish and enforce its company policies on safe driving and making use of travel routes that least impact on area residents and local traffic. Also, the Board would expect Shell to work closely with the town, school bus drivers, and the county to minimize traffic impacts.

7 OTHER ENVIRONMENTAL

Shell

Shell said that an environmental report was prepared to evaluate environmental conditions in the project area, anticipate impacts associated with the development, and propose mitigative measures. The applicant said local residents were consulted on their views on the best location for the plant. The applicant explained that the project area lies for the most part within the eastern slopes area and contains significant wildlife. It said moose and mule deer are the most common big game species with smaller numbers of white tail deer and elk present. In response to questions from Mr. Newsham about elk herds, Shell stated that it would further investigate utilization of the area by elk although it understands the proposed plant site and surrounding area is not highly utilized by moose or elk. Shell stated that it would make the information available to Mr. Newsham. Shell stated that its project would have minimal impact on the major biophysical characteristics of the area and less than 40 hectares of land will be cleared for the plant. The pipelines would follow existing utilities where possible to minimize land disturbance.

Interveners

Mr. Newsham stated that the plant will be built in an excellent area for wildlife. He questioned whether Shell would monitor elk herds in the area. Mr. Newsham said the herd is prolific and he worried about selenium deficiency in the soil.

Board

The Board notes that Shell has provided information on the environmental impact of the demonstration project and has agreed to investigate the elk population of the area. The Board notes that the plant site was selected with input from local residents and believes the applied-for integrated field and plant facilities would have minor impact on the area.

8 COMMUNICATIONS

Shell

Shell stated that providing timely and accurate information to residents in the project area has been a priority since initiation of the Bearberry project. It said it met with the public, civil officals, local media, and service organizations, and has continued its discussions with area residents on an ongoing basis. Shell stated that communication will be an on going process throughout the construction and operation phases of the project. It stated that the community will receive correspondence giving them information on the status of the project. Shell stated that it would also meet with the public at community meetings as requested and it will hold open houses on the project in future. The applicant also stated that it will provide and explain to the community the results of its plant monitoring programs. Additionally, Shell stated that it will be seeking input from the community into the development of its Emergency Response Plans for the wells, gathering systems, and gas plant.

Interveners

The interveners stated that Shell has done a very good job of public relations in keeping the community informed of its plans for the area; however, they explained that concerns still exist. Mr. Newsham indicated that he would like to see a mechanism set up whereby residents could bring concerns about the project operations to the attention of the Board.

Board

The Board agrees that Shell has done a commendable job of explaining its project to the community.

The Board also recognizes that the community still has concerns about the scheme and its potential for impact on the area having regard for development, traffic, and environmental matters. The Board is prepared to have staff participate in Shell's future communication programs with residents and also to be available to the community as a resource which can be called upon to deal specifically with concerns. The Board has staff located in its Red Deer area office available to the public and industry on a 24-hour-per-day basis.

9 DECISION

Having considered the technical, safety, and environmental aspects of the application, the Board believes approval of the subject facility is in the public interest. The Board is therefore prepared to grant an approval subject to concurrence of the Minister of the Environment with respect to environmental matters and also subject to the following additional conditions:

1. Shell work with residents, the town, the county, and trucking firms to develop a code of conduct for truckers delivering or moving products and equipment to and from the Bearberry project area.

2. Shell continue its communications program outlined in section 8 above and advise the Board's Red Deer office as to when community meetings will take place.

3. Shell involve the community in the development of its Emergency Response Plans.

4. Shell submit design features and calculations to show mitigation of any water-hammer effect due to rapid closure of ESD valves.

5. Shell submit design details to show how the production pipeline is protected from the high pressure oil circulating system.

DATED at Calgary, Alberta, on 14 April 1987.

ENERGY RESOURCES CONSERVATION BOARD

Strom

N. A. Strom, P.Eng.
Board Member

Bellows

L. A. Bellows, P.Eng.
Board Member

E. G. Fox

E. G. Fox, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

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AUG - 4 1987

NORCEN ENERGY RESOURCES LIMITED APPLICATION FOR APPROVAL OF A GAS PROCESSING PLANT IN THE CAMPBELL-NAMAO FIELD

Decision D 87-9
Application 861041

1 INTRODUCTION

1.1 Background of Application

Norcen Energy Resources Limited (Norcen) applied on 29 August 1986, pursuant to section 26 of the Oil and Gas Conservation Regulations, for approval to construct and operate a sour gas processing plant. The attached map (Figure 1) shows the location of the proposed plant site, the main interveners' properties, and existing gas plants in the area. The proposed facility would be situated in the southwest quarter of section 1, township 55, range 25, west of the 4th meridian, about 7.0 kilometres (km) north of Edmonton, and would be located in the vicinity of a number of rural subdivisions and within the Campbell-Namao oil and gas field. Norcen's plant would process non-associated and solution gas from wells in several fields in the general area.[1] The raw gas from some of the wells contains small quantities of hydrogen sulphide (H_2S). Although the anticipated maximum H_2S content from these wells would be 2800 parts per million (ppm) (0.28 per cent), due to dilution with sweet gas from other wells, the proposed plant's anticipated maximum H_2S inlet rate would be 848.0 cubic metres per day (m^3/d) of H_2S (1.15 tonnes per day (t/d) sulphur equivalent).

The gas plant would be designed to process a maximum of 1583.0 thousand cubic metres per day (10^3 m^3/d) of raw gas from which 1511 x 10^3 m^3/d of sales gas and 4.6 m^3 of pentanes plus (C_5+) would be recovered. A maximum of 2.30 t/d of sulphur dioxide (SO_2)[2] would be emitted to the atmosphere through a 16.2-metre (m) incinerator stack.

1.2 Matters Leading to the Public Hearing

In accordance with the Board's Guide G-26 (Sour Gas Processing—Plant Applications to the ERCB—A Guide to Content), in early March 1986, Norcen undertook to contact all landowners and occupants in the vicinity of the proposed gas processing plant and to advise them of its possible impacts on the local residents. Each nearby resident was personally contacted and presented with an information package which described the scope of the project and the plant operating characteristics. Residents were encouraged to contact the applicant regarding any concerns they had about the proposal. Subsequently, the applicant undertook to prepare an environmental impact analysis to address those concerns raised by the residents.

In April 1986, residents formed an association known as the Rose Ridge Citizens Committee (RRCC or the Committee) to carry out an independent assessment of the various concerns of those living in the vicinity of the proposed plant and to ensure themselves that such concerns were satisfactorily dealt with before the proposed plant was constructed. The RRCC members represent local residents and landowners living in the general vicinity of the proposed plant site.

In late May 1986, Norcen held a public "open house and information session" for the RRCC and other interested parties to inform them of its proposed development plans, to address concerns raised by residents about the project, and to provide the details of its environmental study. Following the May 1986 open house, Norcen responded to questions and concerns raised by the attendees through telephone conversations, personal visits, and letters. A second public meeting was held in late August 1986, at which time information about the project and other environmental impact data was presented. As part of its public awareness and information exchange program, Norcen also circulated four separate information supplements to the RRCC members.

At the suggestion of and with the assistance of the ERCB, Norcen also entered into a negotiation process with the RRCC. The applicant advanced funds to the RRCC to retain independent legal counsel and technical experts to assist the residents in understanding and assessing Norcen's application. There were numerous conversations among Norcen, counsel for the RRCC, and Board staff throughout the negotiation process. On two occasions, Board staff offered to meet with RRCC members and provide information about the regulatory review process, compliance requirements of sour gas processors, and facts about the sour gas industry in Alberta. Counsel for the RRCC declined the Board staff's offers and consequently the negotiation process consisted of a series of conference calls among the applicant, Board staff, and counsel for the RRCC. Almost a year after Norcen first notified the residents, the process culminated in a meeting held in mid February 1987. At that time it was concluded that further negotiations would not resolve the residents' remaining concerns about Norcen's project and that the application and concerns of the residents would have to be dealt with at a public hearing.

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[1] Solution gas comes from a producing oil well and non-associated gas comes from a gas well.

[2] Sulphur dioxide is a compound formed during combustion from equal weights of sulphur and oxygen. Therefore, the maximum daily emissions can be described as either 2.30 t/d of SO_2 or 1.15 t/d of sulphur.

Consequently, the application was set down for consideration at a public hearing in Cardiff, Alberta, on 17, 18, and 19 March 1987, with Board Members C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and Acting Board Member M. J. Bruni, sitting. Those who appeared at the hearing are listed in the attached table.

1.3 Interventions

The RRCC intervened at the public hearing on behalf of concerned residents and landowners in the area, and stated that its membership included approximately 420 people.

At the outset, the RRCC and the majority of the people expressed strong opposition to the construction of any plant in that area under any circumstances. At the hearing, the RRCC modified its position somewhat to allow the plant to be built, but only if all the sulphur was recovered and there were no emissions of SO_2.

The RRCC expressed concerns about the proposed gas plant's emissions, which it claimed would cause

- corrosion of metal, particularly barbed wire fences and farm machinery,
- degradation of the area's air, soil, and surface water quality, and
- possible impacts on local industries such as honeybee keeping, greenhouse operations, and dairy farming.

Alberta Environment, Westlock-Sturgeon MLA N. Taylor, and C. Crozier, a councillor of the M.D. of Westlock-Sturgeon, appeared and questioned the applicant but did not present evidence.

2 ISSUES

When considering any application, contested or not, the Board must weigh the evidence as submitted in arriving at its decision. First, the purpose of a proposed plant must be established and the technical feasibility and economic viability of the plant weighed. The proposal may fail at that point. If it passes that first test, the potential impacts of the applied-for plant on existing developments and people must be considered, including concerns such as an appropriate plant location, sulphur emissions, corrosion, and possible impacts on local air, soil, and surface water quality. Consideration must also be given to alternative methods of sulphur disposal at the proposed plant site, including recovery, injection, chemical adsorption, and incineration.

If weighing of these matters leads to approval, the impact of the facilities on the community and the people affected by the plant must be considered again to determine appropriate conditions to be imposed on plant design and operation.

In this application, the Board believes the issues can be divided into two broad categories, the technical and environmental matters as submitted in evidence by all parties and a broad category of issues that might be described as public concerns. The public concerns are, of course, related to the technical matters.

More specifically, the health and environmental concerns of the local residents, and their perceptions of the possible impact the plant would have on their lives and businesses, occupied a large part of the hearing. This does not detract from Norcen's attempts to resolve the matter by providing financial assistance to the RRCC to retain technical experts, by conducting public information sessions, and by participating in negotiations.

In summary, the Board considers that the main issues to be addressed are

- the purpose of the proposed gas plant and the public interest,
- the location and impacts of the proposed plant on the area and people, and
- consideration of alternative methods of sulphur disposal.

It must be recognized that in reaching a decision on these issues the Board must weigh the quantifiable data submitted about the plant and the environment against the concerns expressed by citizens about the perceived risk on their lives, their lifestyle, and their community. The Board considers this weighing an important responsibility imposed by the statutes.

3 PURPOSE OF THE PLANT

3.1 Applicant's Views

Norcen stated that the proposed gas plant is required to remove carbon dioxide (CO_2) and H_2S from the high- and low-pressure gas streams so that the gas can be fed into the downstream Norcen St. Albert natural gas liquid recovery plant and its Fort Saskatchewan straddle plant. In the past, the sour gas stream was separated and sent to an industrial sour gas purchaser, but that purchaser has announced its gas requirements are declining and no alternative purchaser for this kind of gas has been found. Also, Norcen indicated that the proposed plant would allow currently shut-in sour gas reserves in the area to be processed and marketed.

Norcen further explained that, if its plant were approved, the Bankeno Resources Ltd. (Bankeno) Morinville gas plant would be dismantled and its raw gas sold to Norcen. Similarly, the total plant expansion scheduled for the Canada Northwest Energy Limited Campbell-Namao plant would not be required. Thus, consolidation of processing facilities within the Cardiff area would occur with approval of Norcen's scheme.

3.2 Interveners' Views

The interveners originally opposed the construction of any plant in the area and questioned why any plant, in addition to those already operating, was needed. After Norcen had presented its evidence with respect to why the plant was required, the RRCC remained concerned with plant location and possible environmental impacts.

3.3 Board's Views

The Board recognizes that some sour gas reserves in the area are currently shut in and that other reserves now being produced would also have to be shut in if additional processing facilities are not provided. Sweetening of the gas would provide better efficiency and more complete conservation of liquids at Norcen's downstream Fort Saskatchewan plant. The production of currently shut-in sour gas reserves would benefit the economy of Alberta and ensure production prior to further surface land development in the Cardiff area. Norcen should not be denied an opportunity to recover and market its resources, and there is a valid purpose for a processing facility in the subject area, provided that construction and operation of the plant would not significantly affect the residents and local natural environment.

The Board notes the residents' question as to why another plant is needed but also notes the applicant's undertaking to consolidate operation of the Bankeno plant with the proposed plant and thus not increase the number of plants in the area.

4 LOCATION AND IMPACTS OF THE PROPOSED PLANT

4.1 Applicant's Views

4.1.1 Choice of a Site

Norcen said the criteria it used in selecting a site for the proposed gas plant included availability of land, population density, proximity to the existing Norcen gathering systems, and economic considerations. The existing Norcen Campbell-Namao plant was rejected due to its proximity to St. Albert and a higher population density.

An abandoned gravel storage yard in the vicinity of the proposed plant site area met the criteria used to select an appropriate site; however, the excessive purchase price of this land made the location uneconomic.

Additionally, the following sites were rejected due to distance from the existing Norcen gathering system:

Norcen—Campbell-Namao battery 5-27-54-25 W4M
Amoco—St. Albert gas plant 14-36-53-26 W4M
Bankeno—Morinville gas plant 11-15-55-25 W4M
Federated—Cardiff Pipeline Pump Station NW 1/4-7-55-24 W4M
Canada Northwest Energy Limited—Campbell-Namao gas plant 13-12-54-25 W4M
Morinville Industrial Subdivision Sec 34-55-24 W4M
Aerlite Quarter SE 1/4-34-54-24 W4M

4.1.2 Impact of the Proposed Plant

The applicant commissioned Western Research to study possible impacts of the proposed gas plant on the local environment. Its environmental report addressed the concerns of the interveners and included an assessment of impacts on ambient air quality, soils, water, agriculture, and human and animal health. Corrosion, which was raised in the RRCC intervention, was also discussed at the public hearing.

Air Quality

Alberta Environment's "Stacks" computer program was used to determine what effects the proposed emissions of SO_2 would have on air quality in the area. The applicant stated that its study took into account existing and proposed local and regional SO_2 emissions. The calculations indicated that under worst-case meteorological conditions and with plume overlap from the Bankeno Morinville plant, a maximum 1-hour SO_2 concentration of 0.142 ppm would be observed. (A comparison of Norcen's proposed air quality and sulphate deposition conditions to the Canadian and Alberta standards is shown in Figure 2 attached.) However, with the consolidation of the Bankeno plant with Norcen's proposed plant, the potential for plume overlap would be eliminated. The applicant stated that its proposed plant's 1-hour maximum would be well below the present Alberta standard of 0.170 ppm. The applicant stated that, under normal operating conditions, which are expected to occur 97.5 per cent of the year, the emission levels from its sour gas plant would be in the order of 0.002 ppm SO_2. Norcen's maximum predicted 1-hour average ground-level concentration of nitrogen oxide associated with all compressor and heater exhausts would be 0.060 ppm, which is also well below the Alberta Environment 1-hour air quality objective of 0.210 ppm.

Western Research's environmental study for Norcen included a discussion of the impacts of SO_2 emissions on various crops. The report tabulated the threshold SO_2 concentration for various crops over several exposure times. The results indicated to Western Research that crop injury should not be experienced at the concentrations expected in the vicinity of the proposed gas plant for either a 1-hour exposure time or for an extended exposure time.

Norcen outlined its plans to conduct continuous ambient air quality monitoring for 2 months per year. This would involve the use of a fixed monitoring trailer which would record H_2S and SO_2 concentrations in the ambient air as well as wind speed and direction. Norcen would also maintain four static monitoring stations near the proposed site. These stations would detect any H_2S present in the ambient air and would indicate total sulphation. These stations would be situated in locations where sulphate deposition is expected to be the highest. All of the monitoring data would be analysed monthly and sent to Alberta Environment in accordance with current monitoring requirements.

Sulphur Deposition

Norcen also contracted Western Research to determine the sulphur deposition rates in the area of its proposed plant. Alberta Environment's SULDEP 2 computer model was used to estimate the annual sulphate deposition rates resulting from SO_2 emissions for both current and future operations in the region. Western Research determined that the total predicted annual sulphate deposition (wet plus dry) in the Carbondale area would at maximum be about 30.0 kilograms per hectare (kg/ha) having regard for background, regional, and local sources. Norcen stated this predicted rate would be well below the annual target level which has been established by government.[3]

Soil Tests

Norcen stated that soil samples taken in the vicinity of the gas plant are rated as Class 1 agricultural soils and are primarily Black Chernozems and Solonetzic soils. Based on site-specific soils data, Norcen rated local soils as having low sensitivity to acidic inputs. The applicant concluded that, because of the low predicted sulphate deposition and the high potential of local soils to buffer acidic inputs, the proposed gas plant emissions should not negatively impact soil quality. Soils at the plant site itself would be removed, stockpiled on site, and vegetated by the applicant for eventual reclamation of the plant site.

Water Quality

During its study in April 1986, Western Research, on behalf of Norcen, conducted water sampling of dugouts in the vicinity of the proposed plant site. The surface water in the area is generally used to supply irrigation water for greenhouse crops, drinking water for livestock, and in some cases stocking of sport fish. The analyses showed minor water quality exceedances for the parameters of alkalinity and iron content. However, the samples indicated that the local surface waters have low sensitivity to acidic input. Norcen concluded that emissions from the proposed plant would have no adverse impacts on the quality of surface waters in the area due to the water chemistry and the predicted low sulphate deposition. In addition, the local watershed was identified as having high buffering potential to reduce acidic input.

Norcen concluded that the maximum SO_2 emissions from its proposed gas plant would have no significant impact on local air, soil, or water quality. The results of its air quality analyses indicated that even under worst-case conditions, the maximum ground-level concentration of SO_2 would remain below the allowable concentration set by Alberta Environment. Norcen emphasized that soil and water analyses showed that the area soils and water possess a high buffering capacity and neither was found to be sensitive to acidic inputs.

Although corrosion was not discussed in the gas plant application, Norcen retained Dr. R. Wallace to rebut the evidence presented at the hearing by Dr. W. Kunda, the RRCC's expert witness. Dr. Wallace, who has been involved in research on corrosion effects on metals due to the energy industry's activity in Alberta, concluded that the low average ground-level concentrations of SO_2 in the vicinity of the proposed plant would have only a small effect on corrosion rates in the area and these effects would not be distinguishable in comparison with corrosion that will normally occur from existing natural processes. Norcen concluded that the expected life of barbed wire or other metal materials in the area would not be materially shortened due to the proposed plant emissions.

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[3] Norcen stated that the target level for annual wet sulphate deposition that has been agreed upon by federal and provincial environment ministers is 20.0 kg/ha. Norcen further stated that studies involving measured deposition rates suggest this level as being protective of all but the most sensitive aquatic environments. It said that, because measured values of wet and dry deposition have been found to be of the same order of magnitude, an equivalent total annual sulphate deposition (wet plus dry) target would be about 40.0 kg/ha (see Figure 2).

4.1.3 Mitigation of Impacts

Norcen stated that it endeavoured to reduce impacts on area residents by its design of the proposed gas processing plant. The applicant included an incinerator stack in its plant design rather than a flare stack. Norcen stated that the acid gas[4] removed by the plant's amine gas sweetening unit would be burned in the incinerator stack. It indicated that incineration has advantages to flaring since it provides better controlled combustion conditions and ensures complete conversion of H_2S to SO_2. The applicant stated that another advantage of the incinerator is the absence of the perpetual visual flame associated with flare stacks. Norcen concluded that its proposed 16.2-m incinerator stack would provide adequate dispersion of SO_2 and would ensure that ground-level concentrations comply with ambient air quality standards.

Norcen also committed to planting shrubs along a berm which would surround the plant site. It indicated the shrubs would likely aid in the attenuation of noise from the plant.

The applicant contacted other operators in the vicinity of the proposed gas processing plant in the hope of consolidating gas processing facilities in the area. As a result, it reached an agreement with Bankeno to decommission and remove its plant in Lsd 11-15-55-25 W4M if Norcen's scheme was approved. The applicant also developed a processing agreement with Canada Northwest Energy Limited which would eliminate the need for the full expansion of the gas plant in Lsd 13-12-54-25 W4M.

In response to concerns expressed by interveners at the hearing, the applicant committed to

- install continuous ambient air quality monitoring during the first 3 months of operation, including start-up,
- continue discussions with the RRCC regarding monitoring programs,
- house the compression equipment, which would be transferred from other locations, in acoustically insulated buildings, and conduct noise studies to determine the feasibility of installing hospital-type mufflers, and
- continue communication with the RRCC regarding scheduling of trucks, landscaping, plant entrance, tree planting, colour of paint to be used, and other matters relating to aesthetics.

4.2 Interveners' Views

4.2.1 Location

The intervention submitted by the RRCC indicated that the plant location was not suitable because of the population density of the area and because of specialized activities in the area such as bee keeping, market gardening, and greenhouse operations. The RRCC said that the plant location was not chosen having regard for pollution control, but was chosen because the land upon which the proposed plant would be situated was under foreclosure and therefore Norcen was able to purchase it cheaply.

4.2.2 Environmental Impacts

In the RRCC written intervention, environmental concerns about air quality, soil acidification, and the effect of SO_2 on animals, bees, plants, and crops were presented. Concerns about possible metal corrosion were also identified in the interventions and expressed at the hearing.

The RRCC claimed that the predicted maximum ground-level SO_2 concentration of 0.142 ppm would in effect have its members "living in an atmosphere in terms of sulphur dioxide equivalent to the highly polluted atmosphere of Chicago".

The RRCC also indicated that residents would experience stress as a result of having a new gas plant in their vicinity.

The intervention stated that area residents were concerned about the predicted levels of sulphate deposition in the area and its effect on soil quality. They were also concerned that their fertilizer application rates would be difficult to determine because of the erratic nature of the sulphate deposition resulting from plant emissions. Concern was raised by B. Blach, a member of the RRCC executive, that the soil samples taken by Western Research were not representative. He said that, because of variation in soil composition, normally 10 to 15 sites per quarter section were required to obtain useful information regarding soil characteristics.

The intervention also stated that many of the hybrid plants grown in commercial greenhouses in the vicinity of the proposed plant are very sensitive to SO_2. M. Silito, a local greenhouse operator, said that personnel at the Alberta Tree Nurseries of the Alberta Government indicated that damage to his crop of English cucumbers could occur because of SO_2 concentrations of 1.0 ppm with demise within a few hours. Damage to tomatoes could also occur when exposed to SO_2 concentrations of 0.10 ppm with total product loss within a few hours.

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[4] Acid gas is a mixture of H_2S, CO_2, and water vapour removed from the raw gas during processing.

The RRCC read into the record a letter from a Dr. Armrod of the University of Guelph to J. Bocock, an area resident. The letter stated that "the overall patterns illustrated by Figures 3 and 4 indicate that continuous exposure to 140 parts per billion (0.14 ppm), is likely to decrease growth and yield of crops."

The RRCC also indicated that no SO_2 emissions should be permitted until it could be be shown that long-term, low-level exposure would have no detrimental effects on animals. As outlined in its 9 March 1987 intervention, it claimed a test conducted on honeybees in Montana indicated a low-level (0.10 ppm) concentration of SO_2 has an effect on bees' ability to detect and gather nectar when they are exposed to this SO_2 level over an extended period of time.

The RRCC argued that the potential corrosive effects of SO_2 and other emissions from the plant were of great concern to the residents in the area. They stated that in the area of the plant there were many barbed wire fences, granaries, metal farm buildings, residential buildings, farm equipment, and motor vehicles, all of which would be susceptible to corrosion. The RRCC retained Westra & Associates to evaluate the corrosive nature of SO_2. The evaluation was mainly an interpretation of the findings presented in the recent CPA report entitled "A Review of Corrosion with Reference to Rural Alberta". Westra & Associates concluded that SO_2 emissions have an effect on corrosion rates; however, its final analysis was that the degree of damage to farm machinery and fences due to corrosion is difficult to predict without long-range tests.

In conclusion, the Committee stated that, despite the testimony of Norcen's witnesses, and despite evidence presented to the Board at previous public hearings, the Committee still remained concerned that the proposed plant's emissions could cause environmental damage and adversely affect human health. The RRCC believed that, in order for Norcen to process sour reserves at its proposed plant, some form of sulphur recovery should be implemented to ensure that there would be no emissions of H_2S or SO_2 to the atmosphere.

4.3 Board's Views

4.3.1 Location

The population density near the proposed site is not high, but to a degree this is relative to perceived and actual impacts. At the hearing, the interveners' technical expert, F. Reintjes of Reintjes Engineering Ltd. (Reintjes), agreed with Norcen that the site it chose was optimal in terms of economics and location relative to the gathering system, and the Board concurs with this assessment.

No alternative locations were presented at the hearing that would put the proposed plant in an area of much lower population density and still ensure reasonable proximity to the gathering system. The population density in the area of the existing Campbell-Namao plant is significantly higher than in the area of the proposed plant and on the basis of population density the Campbell-Namao site would not be chosen. During the hearing a more suitable plant location was not identified, and therefore the Board concludes that Norcen's proposed location would be appropriate provided any resulting impacts were not significant.

4.3.2 Impacts of the Proposed Plant

The Board notes that in its intervention the RRCC misinterpreted Norcen's data about the quality of the ambient air in the vicinity of the proposed plant. The RRCC said that the mean **annual** SO_2 concentration in Chicago is 0.140 ppm. It incorrectly compared that concentration to Norcen's maximum predicted **1-hour** average ground-level SO_2 concentration of 0.142 ppm. For a proper and accurate comparison the RRCC should have compared Chicago's annual average SO_2 concentration of 0.140 ppm to Norcen's maximum annual average SO_2 concentration of 0.002 ppm which it predicted would occur in the area of its proposed plant. This misinterpretation was corrected during the hearing.

The applicant is compelled, and the plant is designed, to comply with the current legislation to meet the established Alberta air quality objective of 0.17 ppm of SO_2 as a 1-hour maximum (see Figure 2). This is the level considered by Alberta Environment to be protective of the environment. Since the maximum 1-hour ground-level concentration expected under worst-case conditions would be less than 0.17 ppm, and the daily and annual average ground-level SO_2 concentrations would be less than that, the Board accepts Norcen's position that there would not be a significant adverse effect on the area's ambient air quality.

The evidence regarding soil and water quality submitted in the application stated that the plant emissions would be minor and would not adversely affect the quality of either the area's soil or water because both soil and water were capable of absorbing, without undue effects, much larger quantities of sulphate than would actually be deposited. While Norcen's soil testing methods were challenged by certain members of the RRCC, no tangible evidence was put forward by the interveners to demonstrate that there could be significant impacts. The Board notes that the RRCC did not cross-examine Norcen's witnesses on the greater part of the environmental study that the applicant conducted. Although the Board accepts Norcen's evidence that soil and water quality would remain satisfactory, should the plant be approved Norcen would be expected to verify its conclusions by periodic tests.

Evidence was also presented regarding short-term and long-term effects of SO_2 emissions on crops, animals, and humans. As noted in Figure 2, Norcen's maximum and expected 1-hour average ground-level SO_2 concentrations are relatively minor and well below the standards set to protect the environment and animal and human health.

As previously stated, the Alberta ambient air quality standard for SO_2, limiting ground-level concentrations to 0.17 ppm as a 1-hour maximum would be met, thus indicating that there should be no adverse effects in the short term. Furthermore, the Board notes that plant operators are required to report ambient violations whenever the average **daily** SO_2 concentrations exceed 0.06 ppm. Additionally, the **annual** average ground-level SO_2 concentration specified by Alberta Environment is 0.01 ppm. The Board recognizes that Norcen has committed to monitor ambient air quality if the plant is approved and the Board would require the applicant to show that long-term average SO_2 concentrations would not approach the maximums specified by the province's ambient air quality objectives. This would ensure that a ground-level SO_2 concentration of 0.10 ppm, which was of concern to the interveners relative to crops and bees, would not be experienced over any significant period of time. Norcen projected a significantly better long-term performance than 0.17 ppm and, if it were not able to achieve this, then it would have to modify its proposed operations accordingly or the matter would have to be reopened for review in light of the data recorded at the time.

The Board notes that long-term impacts from SO_2 emissions, determined by Norcen, were in relation to annual sulphate deposition. The Board recognizes that Norcen's determination of a maximum deposition rate of 30.0 kg/ha per year, as noted in Figure 2, would only occur if and when all background sources and all existing and proposed emitting sources in the Carbondale area are continuously emitting SO_2 at their maximum permissible rates throughout the entire year. The Board believes that this predicted maximum sulphate deposition rate would occur over a very short period during any year if it occurred at all. The Board expects Norcen's plant would be typical of most gas processing plants in the province, the majority of which do not operate at their maximum design rates for any sustained periods of time because of gas market constraints. Therefore, the proposed plant would likely operate at more intermediate rates. Having regard for the fluctuations in throughputs and the corresponding reduced SO_2 emission rates, the Board believes that the actual sulphate deposition rates in the Carbondale area would be significantly less than the maximum annual 30.0 kg/ha rate that Norcen predicted using the mathematical equations and the SULDEP model.

Therefore, the Board is satisfied that there would be no long-term impacts on crops or bees in the area from SO_2 emissions from Norcen's proposed plant. The Board also accepts Norcen's evidence that any increase in corrosion in the area because of the SO_2 emissions from the proposed facility would not be noticeable in comparison to corrosion from the current causes.

5 CONSIDERATION OF ALTERNATIVE METHODS OF SULPHUR DISPOSAL

5.1 Applicant's Views

Norcen stated that, if its application were approved, the plant's feed gas would contain a maximum of 848.0 m^3/d of H_2S (1.15 t/d of sulphur equivalent). Although Norcen argued that its proposed plant design could meet all environmental standards and have little or no impact on the biophysical and human environment, it had investigated the available options and related implications of removing all sulphur compounds from the gas stream. This investigation was done largely in response to the concerns expressed by the local community. Prior to final plant design, it investigated six sulphur handling and disposal options, four of which could reportedly remove all or most of the sulphur from the acid gas stream.

- Norcen considered recovering sulphur by installing a modified Claus sulphur recovery unit although it did not know of any small-scale industrial application of the Claus process. Based on the unproven operation of a Claus unit in such applications, and recognizing that the plant's maximum sulphur inlet rate would be 1.15 t/d, Norcen discounted this option as being a viable alternative.

- The applicant evaluated the feasibility of utilizing a "Lo-Cat" sulphur recovery process which uses a liquid catalyst to remove H_2S from the acid gas stream in the form of a sulphur slurry. Norcen estimated the capital cost of the Lo-Cat to be $1 050 000 (Canadian). The applicant stated that, unlike the Claus process which produces marketable elemental sulphur, the Lo-Cat process produces a sulphur slurry which is not readily marketable and would require a sulphur melter to produce a saleable sulphur product. Alternatively, the slurry would have to be disposed of in an approved landfill. Norcen indicated that a Lo-Cat unit would require minor piping and process modifications prior to use at its facility. In conclusion, Norcen stated that the capital outlay required and the current absence of a market for the sulphur product resulted in its rejection of the Lo-Cat process.

- The third option considered by Norcen was the installation of an iron sponge unit. The iron sponge process uses wood chips impregnated with iron oxide to react with H_2S, forming iron sulphide. The "spent" iron sponge would have to be disposed of at a landfill site. Norcen said that the disposal of some 8.5 m^3/d of spent iron sulphide wood chips would create a potential environmental problem for the watershed in the disposal area. This process was rejected because of the environmental concerns.
- The fourth option considered was to recover sulphur by installing a Budra One Step Desulphurization Process. Norcen said this process is still in the experimental stages and this technology has not been applied commercially anywhere in the province. The applicant felt that because of the importance of this scheme, and having regard for the area, this was not the place to test an unproven, developing process.
- Another alternative evaluated was the feasibility of injecting the acid gas stream into a subsurface formation. Norcen said it rejected this option because of the technical problems and safety concerns associated with the dehydration, pipelining, and compression of the acid gas. Additionally, Norcen said this option would not be economically viable given the capital and operating costs for acid gas compression and sour gas pipelines.
- As the sixth sulphur handling and disposal option, Norcen proposed that all the H_2S and CO_2 removed from the acid gas be incinerated and emitted to the atmosphere as SO_2 through a 16.2-m incinerator stack.

5.2 Interveners' Views

The RRCC stated that, if Norcen plans to build a plant in the area, the plant must be designed to alleviate any and all possible adverse impacts on the area residents. Reintjes considered the merits of using the Lo-Cat Hydrogen Sulphide Oxidation Process, the Chiyoda Flue Gas Desulphurization Process, and the Budra One Step Desulphurization Process for sulphur recovery at the proposed plant. Reintjes stated the Lo-Cat process has been under development since 1972 and the first installation of the unit in Canada was completed in 1984 at the Cochrane, Alberta Natural Gas Company Ltd plant. Reintjes' cost estimate for the installation of a Lo-Cat at Norcen's proposed plant was $713 770 (Canadian). He acknowledged, however, that this estimate was low if a process configuration assumed by Norcen were to be installed. The feasibility of installing a Chiyoda Flue Gas Unit was evaluated, and Reintjes concluded that further development to this new, unproven process would be required, prior to installation at a processing scheme such as Norcen's proposal. He also evaluated the Budra One Step process. The Budra system is a new process which, unlike the Lo-Cat, is claimed to be capable of producing a saleable sulphur product. Reintjes estimated a cost of $400 000 for a skid-mounted unit for use at Norcen's proposed facility. Reintjes acknowledged that to date there has been no commercial application of the Budra system and though the system looks favourable, it would require further investigation, including pilot testing before installation in a commercial operation.

5.3 Board's Views

The Board believes that most of the alternative acid gas disposal options investigated by Norcen are either not operationally practical or are not economically justifiable. It agrees with the applicant that the incineration option is the most suitable sulphur disposal method in this case, considering the proposed modest emission of sulphur and the minor impacts identified.

The construction and operation of a sulphur plant for the low sulphur volumes and low impacts is, in the Board's view, not practical or economic in this case. The Board notes that as the reservoirs deplete, the proposed plant's production rates would decline and this could result in operational problems at the sulphur plant which might require frequent flaring. The amount and kind of sulphur that would be recovered with the Lo-Cat unit would not justify its installation and would likely involve the disposal of the sulphur slurry to a landfill.

The interveners proposed the Budra process which, in the Board's view, is in the experimental stage and may best be categorized as developing technology. The process has not yet been proven and its installation at a scheme such as Norcen's would not be appropriate as this experimental process could create more serious environmental effects than Norcen's proposed option.

The Board is satisfied that the applicant's proposal to incinerate the acid gas will result in compliance with Alberta Environment's regulations for ground-level concentrations of SO_2, which are more stringent than required national maximums and correspond directly with the Environment Canada Maximum Desirable Objectives. It believes that a properly designed and controlled incineration system will ensure complete and continuous combustion of H_2S, low ground-level concentrations of SO_2, and a low probability of odour problems. Norcen would be required to achieve this.

6 DECISION

The Board has carefully considered all of the evidence and is satisfied that the proposed plant would meet or exceed all existing regulations and requirements that are the Alberta standards for safeguarding public health, safety, and the natural environment. While the Board recognizes that the concerns of the interveners are real, it believes that they reflect a perception of the possible impacts not substantiated by evidence. The evidence shows that the plant could be built and operated with minimal impact on the area. To assure local residents that plant operations would be in accordance with the terms set out in Norcen's application and with the commitments made by the applicant during the hearing, the Board will require Norcen to fulfill the following conditions:

1. Norcen will establish an on-going framework to communicate with the local citizens about the performance of its plant. The ERCB should be provided the opportunity to participate in the process.
2. Norcen will design and conduct a thorough soil-testing program in the areas identified to receive the highest sulphur deposition and report on the findings to the community and any affected party. This program should be consistent with normal requirements of Alberta Environment and should include some baseline monitoring prior to construction of the plant.
3. Norcen will install, for at least the first 2 years of plant operations, continuous ambient air monitoring equipment in suitable locations to determine the effect that the plant emissions would have on the area's air and water quality. This is related to concern for beekeeping and greenhouse operations. The monitoring requirements, which should also provide for some baseline data acquisition, would be co-ordinated with the conditions of operations specified by Alberta Environment.
4. Norcen will prepare and provide an annual report on the environmental effect of air, water, and soil quality during the first 2 years of operation. The final reports are to be reviewed with the community and must be filed with Alberta Environment and the ERCB. At that time, the Board would review the results for the first 2 years with a view to relaxing the requirements if appropriate.

If continuous testing as per the above conditions confirms there are minimal impacts as described in the application, a less rigorous program would then be implemented at the end of 2 years. In any event, the Board would expect the communication program to continue in a suitable fashion as long as there is a real need for it.

Therefore, subject to receipt of the required approval of the Minister of the Environment with respect to environmental matters, the Board is prepared to issue an approval to Norcen for the construction and operation of the gas plant.

DATED at Calgary, Alberta, on 15 July 1987.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

M. J. Bruni
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives **(Abbreviations Used in Report)**	**Witnesses**
Norcen Energy Resources Limited (Norcen) D. G. Davies	S. C. Horne, P.Eng. J. G. Schopp, P.Eng. all of Norcen Energy Resources Limited G. P. Latonas C. F. Raynard M. B. Schroeder all of Western Research, a Division of Bow Valley Resources Services Ltd. Dr. R. Wallace of Dominion Ecological Consulting Ltd.
Technical Experts Assisting the Rose Ridge Citizens Committee (RRCC) W. K. Mis	Dr. W. Kunda Research Associate with Department of Mining, University of Alberta F. J. Reintjes, P.Eng. of Reintjes Engineering Ltd.
A Group of Residents Comprising the RRCC W. K. Mis	W. Blach J. Bocock I. Pasay S. Silito A. Sinkovics P. Zuidema
Councillor in the Municipal District of Sturgeon #90 C. Crozier	
MLA for Constituency of Westlock-Sturgeon N. Taylor, P.Eng.	
Alberta Environment staff S. L. Dobko, P.Eng. C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff H. R. Hansford M. Semchuck, C.E.T. T. M. Bors, C.E.T. M. T. Pittman	

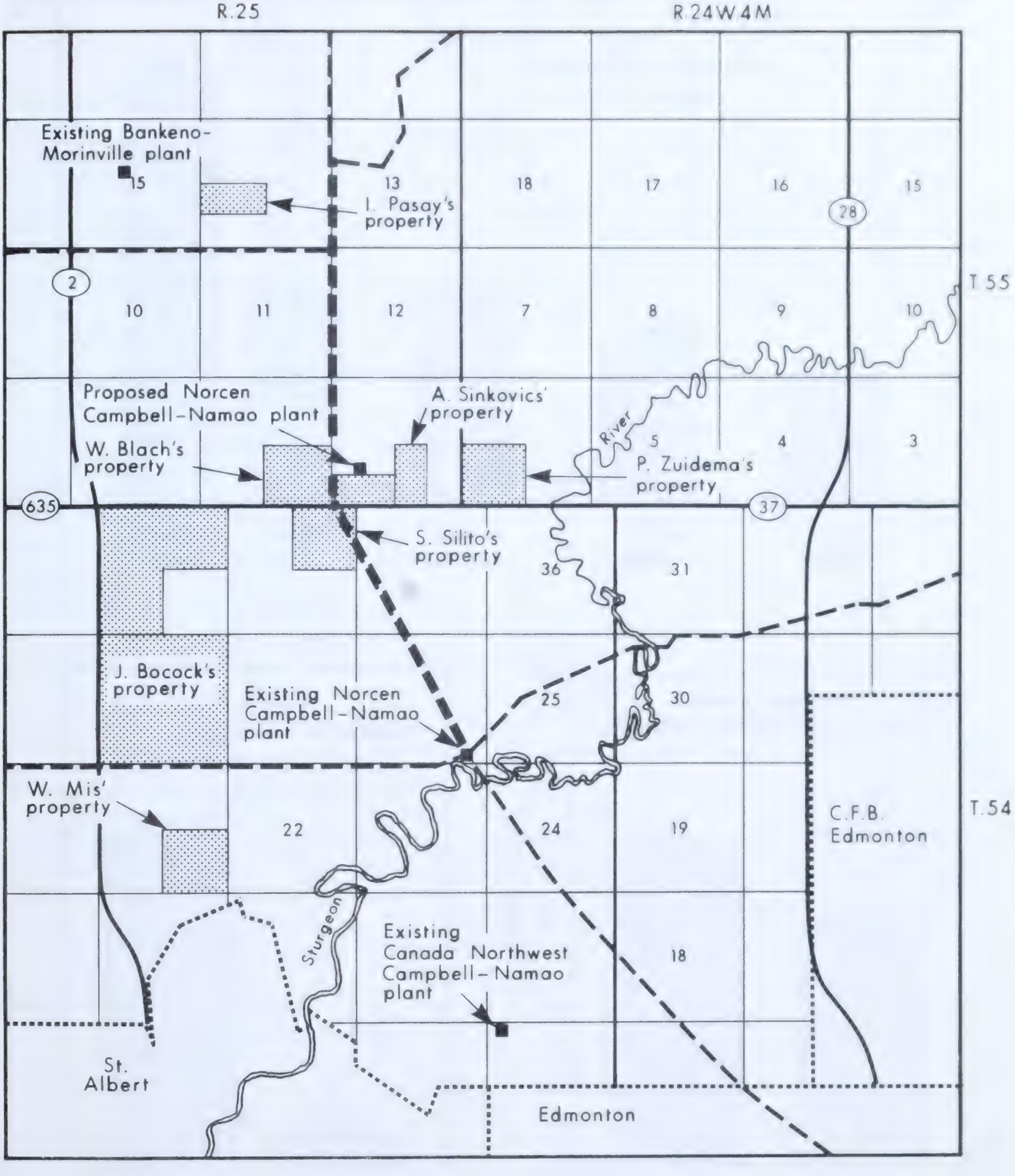

FIGURE 1 NORCEN'S PROPOSED CAMPBELL-NAMAO GAS PLANT AND SURROUNDING AREA
Application No. 861041

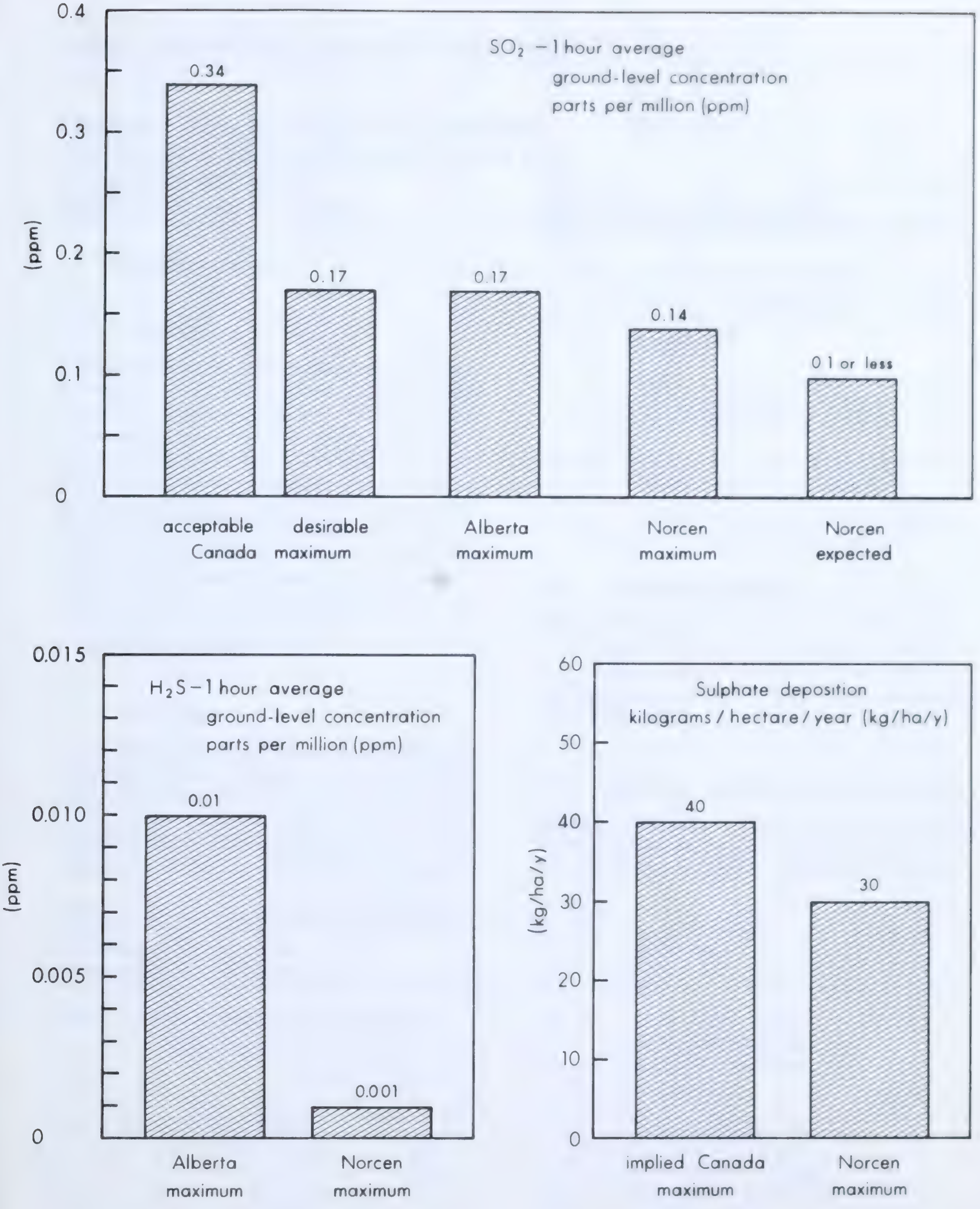

FIGURE 2 NORCEN CAMPBELL – NAMAO AIR QUALITY AND DEPOSITION CONDITIONS AS COMPARED TO ALBERTA AND CANADIAN STANDARDS

ENERGY RESOURCES CONSERVATION BOARD

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Calgary Alberta

CHEVRON CANADA RESOURCES LIMITED AMENDMENT TO BOARD APPROVAL NO. 5147 ENHANCED RECOVERY MITSUE GILWOOD A POOL

Decision D 87-10
Application 861314

1 INTRODUCTION

1.1 Application

Chevron Canada Resources Limited (Chevron), on behalf of the Mitsue Gilwood Sand Unit No. 1 (Unit), applied pursuant to section 26 of the Oil and Gas Conservation Act for an amendment to Approval No. 5147 to permit conversion of the well, CHEVRON MGSU 1 MITSUE 4-27-73-5 W5M (the 4-27 well), to fresh water injection service. The general area of the application is shown on the attached figure. Chevron proposes to inject fresh water at the 4-27 well for the purposes of repressuring the miscible flood pattern in section 21-73-5 W5M, miscible fluid confinement, and pressure support for waterflood producers in sections 27, 28, and 34-73-5 W5M.

1.2 Intervention

Gascan Resources Ltd. (Gascan), as operator of an adjoining waterflood project, filed an intervention stating that water injection at the 4-27 well would potentially result in a loss of recoverable oil and the premature flooding of Gascan's offsetting scheme producer in 02/2-27-73-5 W5M (the A2-27 well). If injection at the 4-27 well was determined by the Board to be reasonable and appropriate, Gascan proposed the following conditions be established to minimize potential adverse effects:

(a) the maximum wellhead injection pressure shall not exceed the formation fracture pressure extrapolated to the surface, or 10 MPa;

(b) the maximum water injection volume shall not exceed 250 m^3/d on a daily basis;

(c) the 4-27 well shall not be acid fractured or hydraulically fractured with a proppant.

1.3 Hearing and Participants

The application was considered at a public hearing in Calgary, Alberta, on 9 and 15 April 1987, with N. A. Strom, P.Eng., F. J. Mink, P.Eng., and H. J. Webber, P.Eng., sitting. The participants are listed in the following table.

2 DECISION AND INTERIM CONDITIONS

Based on the evidence of the applicant, the position of the intervener, and the substantial agreement between the parties on the suitability of and need for water

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chevron Canada Resources Limited (Chevron) J. Stein, Q.C.	C. G. Folden, P.Eng. G. R. Jackson, P.Eng. E.J.B. Wasyliw, P.Eng. L. J. Stewart
Gascan Resources Ltd. (Gascan) A. L. McLarty	E. H. Moumdjian, P.Eng. A. Settari, P.Eng. and R. C. Bachmann, P.Eng. of Simtech Consulting Services Ltd.
Energy Resources Conservation Board staff A. Broughton R. J. Willard, P.Eng. J. Werth, P.Eng.	

injection at the 4-27 well, the Board decided to approve the application at the conclusion of the hearing. In announcing its decision, the Board recognized the need for water injection to commence soon. However, bearing in mind Gascan's concerns, the Board further indicated that the well would be initially subject to conditions as set out in the Gascan intervention. The Board noted that the need for a permanent set of conditions and a procedure to meet Chevron's desire for expeditious consideration of well workover measures would be addressed in its final report after the Board had an opportunity to fully evaluate the evidence.

3 ISSUES

Having regard for the above, the only issues to be resolved are

(a) the need for injection controls, and

(b) the procedure for expeditious consideration of requests to vary any conditions that may be imposed.

4 NEED FOR INJECTION CONTROLS

4.1 Views of Chevron

Though Chevron viewed the question of injection well stimulation, such as well fracturing, to be more in the realm of routine well servicing and not suitable for regulatory control, it accepted that a maximum wellhead operating pressure of 15 MPa would be a reasonable safeguard. Chevron referred to its own field experience which indicated that wellhead formation breakdown pressures were roughly in the range of 30 to 40 MPa during hydraulic fracture treatments. However, under cross-examination, Chevron acknowledged its own evidence suggested that a wellhead pressure of 18 MPa could result in formation breakdown during water injection activities in some parts of the pool.

Chevron contended that if the 4-27 well was unintentionally fractured at a wellhead pressure of 15 MPa, the fracture would propagate only a few metres into the formation due to the high fluid loss associated with fresh water injection and bearing in mind that the surface facilities would limit injection to no more than 600 m^3/d of water to the 4-27 well. On this basis, Chevron dismissed the possibility of an uncontrolled propagation of a fracture at the 4-27 well and the need to establish a maximum injection rate limitation as suggested by Gascan.

Chevron agreed with Gascan that injection at the 4-27 well would result in a negative impact, related to early water breakthrough, at the A2-27 well under a worst-case scenario. Under that circumstance, well fractures at 4-27 and A2-27 would have to be oriented in an east-west direction with a combined fracture half-length greater than 25 per cent of the 800-m interwell distance. Chevron viewed an east-west fracture orientation as only a remote possibility. Based on its field experience involving some 100 wells and a submitted case study involving the wells in 13-22 and 1-28-69-3 W5M, Chevron concluded that the fracture orientation in the pool was northeast-southwest. This conforms with current geotechnical theory and is consistent with province-wide experience. Hence, Chevron perceived little possibility of detrimental impact at the A2-27 well even if the 4-27 well were hydraulically fractured. On this basis, Chevron disputed the need for any conditions restricting fracture stimulation on the 4-27 well.

Chevron also doubted there would be a need to apply a fracture treatment on the 4-27 well to meet its expected injection capability of 250 m^3/d. However, Chevron was concerned that if restrictions were imposed, the procedure for obtaining Board approval to vary the restrictions would be cumbersome and hinder good field management practices.

4.2 Views of Gascan

Gascan submitted that while it did not want to inhibit Chevron's operations, it had concerns about the possible adverse impact at the A2-27 well if uncontrolled injection at the 4-27 well occurred. In Gascan's view, fracturing of the formation at 4-27, whether inadvertent or intentional, could lead to very large volumes of water being injected at an uncontrolled rate. The result could be very premature water intrusion to its A2-27 well. Gascan presented the conditions set out in its intervention as reasonable limitations which would provide reasonable protection against such a possibility.

In support of its argument, Gascan presented a report by Simtech Consulting Services Ltd. (Simtech). The report referred to literature which illustrated the severity of production decline and recovery reduction at an offsetting producer. This analysis assumed that injector and producer were hydraulically fractured creating a combined interwell fracture length equal to 25 per cent of the interwell distance, and that the orientation of those fractures was the same as a straight line connecting the wells. Referring to the area of application, Gascan acknowledged that fracture orientation would have to be close to the east-west direction for this high-risk situation to apply. Under questioning it agreed that the fracture orientation for the province was typically in a northeast-southwest direction. However, Gascan pointed out that variations may exist on a well-by-well basis by as much as 20 to 30 degrees. In sum, Gascan was concerned that fracturing could create the potential for early water breakthrough at its well. Accordingly it asked the Board to constrain Chevron from conducting any fracture stimulation or overpressuring the formation of the 4-27 well without sufficient evidence to show that there would be minimal adverse impact.

To avoid the propagation of an unintentional fracture at the 4-27 well, Gascan proposed the application of a maximum permissible wellhead injection pressure of 10 MPa and a maximum injection rate of 250 m^3/d. Gascan based its proposed maximum wellhead pressure of 10 MPa on estimates of the fracture opening and closure pressure (PFOC) instead of the formation breakdown pressure. Gascan said this approach was justified on the basis that the PFOC is the governing pressure for propagation of the fracture after the formation breakdown pressure has been exceeded. Due to the uncertainty associated with formation fracturing theory and practice, Gascan proposed the maximum injection rate limitation of 250 m^3/d as an additional safeguard to prevent an uncontrollable propagation of an accidental fracture under normal injection operations subject to the wellhead pressure limit of 10 MPa. Gascan stated it would not be opposed to alterations in the maximum wellhead pressure or maximum injection rate if supported by properly conducted field tests.

4.3 Views of the Board

The Board holds the view that good engineering practice is the responsibility of each operator and such practices should be adhered to in order to protect conservation and maintain the correlative interests of other resource owners in the pool. In this sense, while well stimulation practices are not explicitly regulated, it would be incumbent on the applicant to satisfy the Board as to the third-party impact of its proposal. The Board accepts that while there is some risk that unrestricted injection at the 4-27 well may well have a negative impact on Gascan, the evidence submitted does not allow a meaningful assessment of that risk. Under the circumstances, the Board concludes that there is a need for some measure of injection controls to prevent the possibility of adverse and unfair impact at the Gascan A2-27 well. In effect, the Board is prepared to retain Gascan's requested conditions until Chevron submits site-specific technical evidence in support of the establishment of more appropriate control measures.

The Board's view is that if a relatively small induced formation fracture existed at the 4-27 well, the waterflood front would likely be more or less radial with advance being more rapid through more permeable sand lenses and toward areas of lowest reservoir pressure. Also, the Board suspects that limiting the wellhead water injection pressure to 10 MPa to prevent fracturing (as proposed by Gascan) may be somewhat cautious and the limit might reasonably be increased on the strength of well operating experience. The Board believes that the rate of production from wells surrounding the 4-27 well and general reservoir pressure gradients in the vicinity are likely to be the most important factors influencing flood front advance. In the meantime, until suitable operating experience is obtained, the Board considers it appropriate to limit the injection rate at 4-27 to 250 m^3/d and allow Chevron to demonstrate how this limit may be relaxed.

5 PROCEDURE FOR EXPEDITED REVIEW OF CONDITIONS

Chevron viewed the question of well stimulation as one of routine field practice. It was concerned that inserting conditions such as those proposed by Gascan in the ERCB approval would lead to undesirable regulatory delays in receiving approval to perform such activities as rather routine workovers to maintain adequate sand face injectivity at the 4-27 well. In announcing its decision, the Board acknowledged the need to establish a suitable procedure whereby field engineering decisions would not be hampered by the formal, registered application procedure. At the hearing both parties agreed that an expedited process directed by senior members of the Board's Oil Department would satisfy their concerns.

The issue is one of ensuring that sound field engineering practices are adhered to in such a way that the spirit of this Board decision is met. For the initial conditions that were specified, that would mean assuring that no acid fracturing or hydraulic fracturing with proppant is carried out, that the wellhead injection pressure is controlled so as not to exceed 10 MPa and that the daily water injection does not exceed 250 m^3/d. The Board sees these as engineering details that can be more effectively addressed from time to time by a letter stipulating the conditions that must be met. A conveyance clause would be placed in the approval setting out this provision. Review of the conditions would then be prompted by a letter to the ERCB requesting such review. Upon receipt of such a request with the supporting evidence, the Board's Oil Department would convene a technical review meeting to obtain the views of the Unit operator and Gascan respecting the suitability of the request and would subsequently decide the matter. Since the issues are likely to be largely of a technical nature, the Board believes this procedure would be the most suitable and should allow prompt rulings to be made.

6 DECISION

The Board approves Application 861314 by Chevron Canada Resources Limited for amendment of Approval No. 5147 to allow conversion of the well, CHEVRON MGSU 1 MITSUE 4-27-73-5 W5M, to fresh water injection service. The appropriate amendment of Approval No. 5147 will be issued in the near future. In addition, a letter stipulating the conditions proposed by Gascan and set out in Section 1.2 of this report will be issued by the Board's Oil Department.

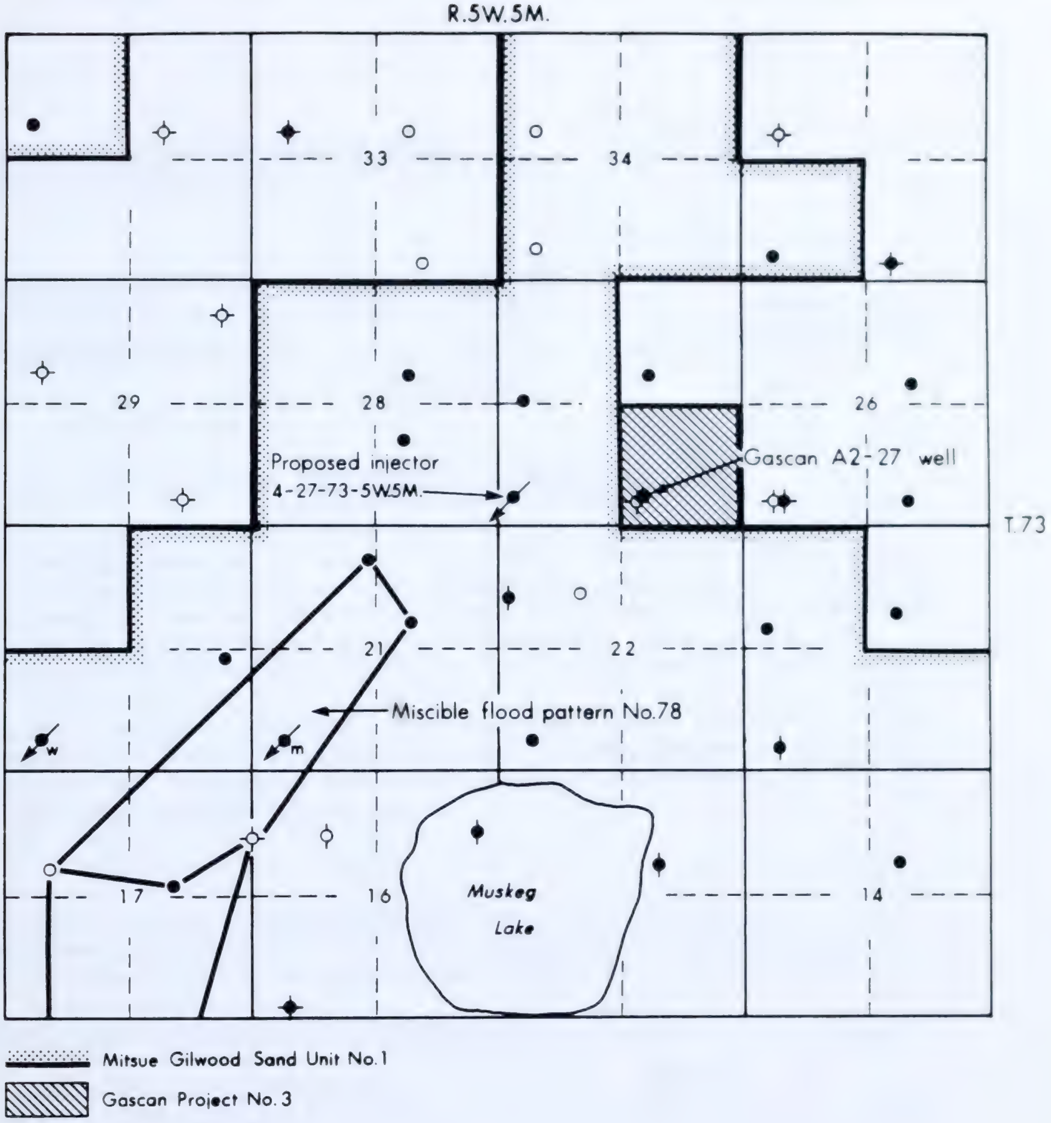
DATED at Calgary, Alberta, on 12 June 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Board Member

H. J. Webber, P.Eng.
Acting Board Member



MITSUE GILWOOD A POOL
Application No. 861314

D 87-10
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PANCANADIAN PETROLEUM LIMITED
APPLICATION FOR A WELL LICENCE
MEDICINE HAT FIELD

Decision D 87-11
Application 870817

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1 INTRODUCTION

1.1 Application and Interventions

PanCanadian Petroleum Limited applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well from a surface location in legal subdivision 5 of section 17, township 13, range 5, west of the 4th meridian. The proposed well, to be known as PCP ET AL MEDICINE HAT 6-17-13-5 (the well), would be for the purpose of obtaining oil production from the Glauconitic Sand.

An objection to the application was received by the Energy Resources Conservation Board (the Board) on behalf of Wahl Builders Ltd. and Harry F. Wahl Management Consultant Ltd., the landowners, and Mr. John Weimer, the occupant of the land.

1.2 Hearing

A public hearing of the application was held on 22 July 1987, in Medicine Hat, Alberta, before Board Members C. J. Goodman, P.Eng., J. P. Prince, Ph.D., and Acting Board Member E. J. Morin, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
PanCanadian Petroleum Limited (PanCanadian) P. R. Murray	P. Cummins, P.Geol. S. Lunn H. Rath, P.Eng. B. A. Steven, P.Eng. W. Tomie
Harry F. Wahl Management Consultant Ltd. Wahl Builders Ltd. Mr. John Weimer H. F. Wahl	H. F. Wahl
Energy Resources Conservation Board staff N. F. Lord, C.E.T.	

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the impact of the well on the land surface, and
- the impact of the well on future development plans for the land surface.

3 VIEWS OF PANCANADIAN

PanCanadian submitted that, by virtue of a petroleum lease it held in conjunction with the City of Medicine Hat, it has the right to explore for and recover the reserves it believes to be present in the drilling spacing unit comprising the southwest quarter of section 17.

It further submitted that the proposed well was needed to attempt to better define and establish the limits of the Board-defined Medicine Hat Glauconitic C Pool.

PanCanadian submitted that it had chosen the well location in order to minimize any adverse impact on the surface of the land. PanCanadian interpreted its geologic target, the Glauconitic Sand, to be a fairly uniform sand development over the drilling spacing unit. Therefore movement of the well location was not greatly restricted because of geologic parameters but primarily because of surface and target area considerations. The spacing in the area of application is currently one quarter section for the production of oil from the Glauconitic Sand. The Medicine Hat Glauconitic C Pool has been primarily developed on 32-hectare and 16-hectare drilling spacing units. It was therefore PanCanadian's desire that the bottom-hole location of the proposed well be on target and consistent with this reduced drilling spacing unit pattern. To this end, PanCanadian was prepared to directionally drill the well from a surface location in Lsd 5 to a bottom-hole location in Lsd 6-17-13-5 W4M (see figure). PanCanadian believed this proposed location to be desirable because it was situated adjacent to an existing well site located in Lsd 6. Further, PanCanadian could utilize the existing access road to the 6-17 location in order to access its proposed location. As the surface of the land was not under cultivation, PanCanadian was of the opinion that the location would have little effect on agricultural activities. If, however, the land was to be utilized for the grazing of livestock, PanCanadian was prepared to fence the lease.

PanCanadian submitted that it had considered three alternative locations prior to selecting the proposed site. PanCanadian had originally proposed that the well be situated on the east side of the existing well location. However, this was dismissed because of the potential for the South Saskatchewan River banks to slump and damage the well.

PanCanadian had approached the landowner on the east side of the South Saskatchewan River (see figure), but the owner, Short Grass Ranches, was not agreeable to a well site on its land as the area was currently under pivot irrigation. Also, PanCanadian stated that because of the necessity of having to directionally drill a considerable distance to reach the proposed target, this location would entail greatly increased drilling costs.

PanCanadian had also considered a fourth location in the northwest quarter of section 17 but as this land was currently cultivated, PanCanadian believed its presently proposed location was preferable.

PanCanadian recognized the interveners' concerns with respect to the possibility of encountering hydrogen sulphide (H_2S) in the well and had amended its application so that the well would not penetrate any zones known to contain H_2S.

With respect to the interveners' comments that the presence of the well site would preclude irrigation in the quarter section, PanCanadian submitted that since no plans for irrigation were submitted for consideration, the possibility of irrigating at some unknown point in the future should not prejudice its application. PanCanadian submitted, however, that many of its facilities present in the southern region of Alberta coexist with irrigation operations. Respecting the interveners' concern that the well would restrict future residential development of the land, PanCanadian submitted that because the land was currently designated as agricultural land and no formal plans for residential development existed, the development of the area may take place as long as 20 to 30 years in the future, by which time the pool would be depleted and the site reclaimed.

4 VIEWS OF THE INTERVENERS

The interveners did not dispute PanCanadian's right to drill the well or question the need for the well in the specific drilling spacing unit.

The interveners stated that because of the adverse impact the proposed well would have on agricultural activities on the quarter section and any future development plans, the application should be denied. Future plans were contingent on the defined land-use by-law for the quarter section being changed. Although the land is currently classified for agricultural use, the interveners stated that submissions were now being accepted by the planning authorities to consider a change to the by-law. If the land continued to be classified for agricultural use, the interveners' plans were to investigate and possibly irrigate the quarter.

The interveners submitted that, if the well were drilled as applied for and if it were productive, its surface facilities could render irrigation impractical. In addition, the interveners also believed that the road PanCanadian intended to use to access the proposed site was inadequate and would require upgrading. This upgrading would also be an obstruction to agricultural activities and by facilitating public access to the area, would further encourage trespass onto the land.

If the land were reclassified for rural residential development, then the interveners believed the existence of the proposed well would restrict their ability to develop the land as they saw fit. Further, the site itself would present an adverse impact to any prospective buyers for aesthetic reasons. The interveners submitted that considerable time and research had been spent investigating residential development; however, they had no formal development plans to enter as evidence.

The interveners proposed an alternative location south of the applied-for site which they believed would be preferable as it was shielded from view by the surrounding topography.

The interveners requested that, if the Board decided to approve the application, the licence be subject to a number of specific conditions or restrictions addressing such matters as drilling operations, power, fencing, weed control, hours of operation, and notification to the interveners as to when access is required, by whom, and for what purpose.

5 VIEWS OF THE BOARD

The Board accepts that PanCanadian has a right to recover the petroleum reserves from the Glauconitic Sand which may exist under the southwest quarter of section 17. The Board also accepts PanCanadian's desire to obtain additional geologic information to better define the Medicine Hat Glauconitic C Pool. The Board recognizes, however, that this right and need must be weighed against any adverse impacts on land surface-related activities which may arise from drilling and producing the well.

The Board accepts PanCanadian's submission that movement of the well location within the drilling spacing unit is not restricted from a geologic perspective, but recognizes PanCanadian's desire to maintain the predominant spacing pattern of the Medicine Hat Glauconitic C Pool.

To the extent that movement of the well is not restricted geologically, the Board need only consider the impact of the proposed well location on surface activities relative to any alternative well locations which have been suggested. The Board agrees that because of the close proximity to the South Saskachewan River, the originally-proposed well site near the river bank is not desirable. The Board also agrees that an alternative location on the lands of the Short Grass Ranches is not desirable because of the extended distance required to directionally drill and, from an agricultural perspective, because the land is currently under irrigation. The Board accepts that the alternative location in the northwest quarter of section 17 is less desirable as this location would be on lands already under cultivation. The Board notes that at the hearing the interveners suggested a location to the southwest of the proposed site but there was little evidence with respect to that location and the Board could not consider it. This does not preclude continued negotiation between PanCanadian and the interveners independent of the Board's decision respecting the current application and location.

Having dismissed the alternative locations, the Board must weigh the impact of the proposed well site on the surface of the land. The Board believes that, as the land is not currently under cultivation or irrigation and the proposed location is adjacent to an existing well site, the proposed well will have minimal, if any, additional impact on the land surface.

With respect to the interveners' future development plans for either irrigation or residential development, the Board notes that throughout the province these developments coexist with the activities of the petroleum industry. Moreover, since no firm evidence for either irrigation or residential development was presented for the Board to consider, the Board cannot weigh possible scenarios against a documented proposal such as this application for a well licence. Also, restrictions imposed on land development by the presence of wells and related facilities fall under the authority of provincial planning commissions and municipalities. Those regulatory bodies may have the authority to relax or alter such restrictions as are appropriate at the time.

With respect to the interveners' request that any licence issued by the Board be subject to special conditions or restrictions regarding drilling operations, fencing, access, weed control, hours of operation, and electric power, the Board notes the following: With respect to drilling operations and weed control, the operator must comply with the Oil and Gas Conservation Act and Oil and Gas Conservation Regulations in accordance with good oil-field practices. The Board notes PanCanadian's undertaking to fence the location should livestock be placed on the land and believes this appropriate. The Board also notes that with respect to electric power, the interveners had no specific proposal. Regarding access to the site, the Board believes that an operator needs unrestricted access and an all-weather route in order to conduct operations in the most expedient and efficient manner and, if any problems arise, to be able to respond immediately. The Board therefore sees no reason for special restrictions.

7 DECISION

Having reviewed the evidence, the Board is satisfied that the well can proceed without significant impacts on the southwest quarter of section 17. Application 870817 is hereby approved. A licence will be issued in due course.

DATED at Calgary, Alberta, on 9 September, 1987.

ENERGY RESOURCES CONSERVATION BOARD

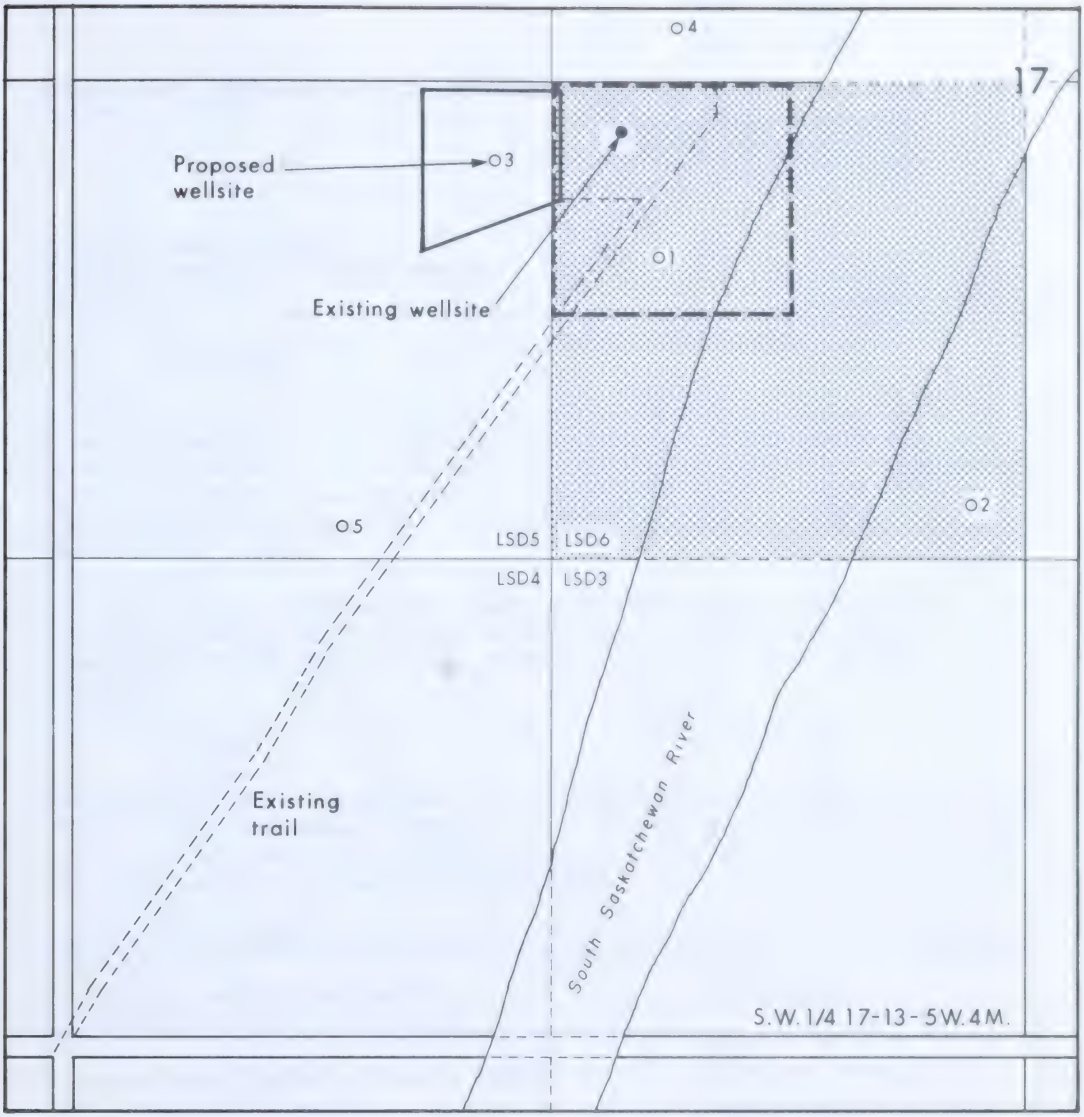
C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Acting Board Member



○ Alternative well locations (approximated).

▨ Target area as per Order No. SU800.

— — Target area 32 hectare drilling spacing unit.

PCP et al MEDICINE HAT 6-17-13-5 W.4M.
Application No. 870817

GOVT. DOCS.
JUL 14 1987

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ALBERTA POWER LIMITED
240-kV TRANSMISSION LINE RE-ROUTE
STAR AREA

Decision D 87-12
Application 870639

1 APPLICATION

Alberta Power Limited applied, pursuant to section 12 of the Hydro and Electric Energy Act, for approval to relocate a 2.4-km portion of a previously approved 240-kV double-circuit transmission line, designated as AP 9L960/9L961 line, which will extend from Deerland substation to the south Lac La Biche area. The proposed relocation is shown on the attached figure.

The need for the transmission line was established in the original application and dealt with in Examiner Report E 86-7 and was not questioned at this hearing. As such it was not an issue at this hearing.

2 HEARING

The application was considered at a public hearing in Edmonton on 8 June 1987, with C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and M. J. Bruni, sitting. The transcript of the hearing and the exhibits constitute the official record relative to this decision.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Power Limited (Alberta Power) K. F. Miller	A. Morin, P.Eng. C. H. Kerslake, P.Eng. M. S. Allen A. Sewlal
R. and S. Pullishy F. McMenemy	R. Pullishy
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff C.J.C. Page J. W. Berg, P.Eng. B. E. Olliver	

3 BACKGROUND TO THE APPLICATION

Alberta Power, by Application 851391 registered on 6 December 1985, applied for approval to construct the new double-circuit transmission line. The application was advertised, several interventions were received, and a public hearing was held at Smoky Lake on 18 March 1986. Examiner Report E 86-7, recommending approval of the project, was adopted by the Board on 5 May 1986. The necessary permits and licences were issued to the applicant on 16 June 1986. The original route applied for and approved in the original application straddled the quarter section line along the entire western boundary of the Pullishy property. Various discussions with the Pullishys and a court injunction prevented the construction on the original alignment and resulted in a revised application by Alberta Power.

Subsequent to the filing of Application 870639 on 7 May 1987 and the filing of the Pullishy intervention on 1 June 1987, further negotiations were entered into between Alberta Power and the Pullishys in an attempt to resolve outstanding questions of tree removal along the quarter line. No agreement was reached prior to the hearing.

Immediately prior to the commencement of the hearing on 8 June 1987, the applicant informed the Board that continued negotiations were being conducted with the Pullishys and requested the hearing be delayed until they were concluded.

4 LOCATION OF THE RE-ROUTE

Alberta Power applied to move the transmission line west onto the Smayda property and entirely off the Pullishy property as described in Application 870639 and as shown on the figure. This re-route was the result of the applicant and the Pullishys being unable to negotiate a satisfactory agreement regarding the impact of and need for removal of the existing windrow along the western boundary of the Pullishy property. For this reason, and to meet a critical in-service date of 1 November 1987, the applicant opted to avoid the Pullishy property.

The Pullishys filed an intervention objecting to the re-route as it would require the removal of a windrow located along the eastern boundary of the SW 29-56-19-W4M which is immediately west of their quarter section (see figure). They contended that the removal of these trees would have the potential for impact to their land.

When the hearing was convened, the applicant, in its opening presentation, informed the Board of a further modification to the applied-for re-route that would involve the installation of one or two additional structures on the Smayda property which Smayda did not oppose. This modification, agreed to by the Pullishys, would effectively increase the ground clearance of the conductors to no less than 3 metres above the tallest trees in the windrow and would have minimal impact on the shelterbelt. The applicant further stated that, since this agreement was reached just prior to the hearing, the final design of this modification would have to be completed and submitted following the hearing. Subsequent to the hearing, the applicant informed the Board and the Pullishys that only one additional structure would be required to achieve the agreed-to clearance. The applicant indicated that the additional cost involved would be about $12 500.

Pullishy's counsel, Mr. McMenemy, upon clarifying the agreement concerning the modified re-route through cross-examination of the applicant, withdrew his client's intervention.

The Board accepts the intervener's position that its prime concern is to maintain the entire windrow of trees along the property line.

Although the Board believes that the parties should have resolved this matter much earlier than the time of application to amend the route, it accepts the proposal of Alberta Power that resulted in the 8 June 1987 agreement with the Pullishys. Given the circumstances, the Board agrees that it would be in the public interest for Alberta Power to absorb the additional cost of construction of the agreed-to modified re-route. The Board also notes that all landowners affected by the re-route have no objection to the modified re-route. The Board believes that the proposed change in design is technically sound, and is satisfied that the proposed re-route, as modified by the agreement of 8 June 1987, is suitable.

5 TIMING OF THE TRANSMISSION LINE

At the hearing, Alberta Power reiterated its position that it is critical that the proposed transmission line be completed and energized by 1 November 1987.

The Board accepts Alberta Power's statement and agrees that it is essential that this in-service date be met.

6 DECISION

The Energy Resources Conservation Board is prepared to approve the modified application with the clear understanding that any affected landowners other than the Pullishys have been informed by the applicant and have agreed to the modified application. The transmission line re-route shall be in accordance with the application and modifications agreed to on 8 June 1987 between Alberta Power and the Pullishys. The requested permits and licences will be issued upon receipt of approval of the Minister of Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 23 June 1987.

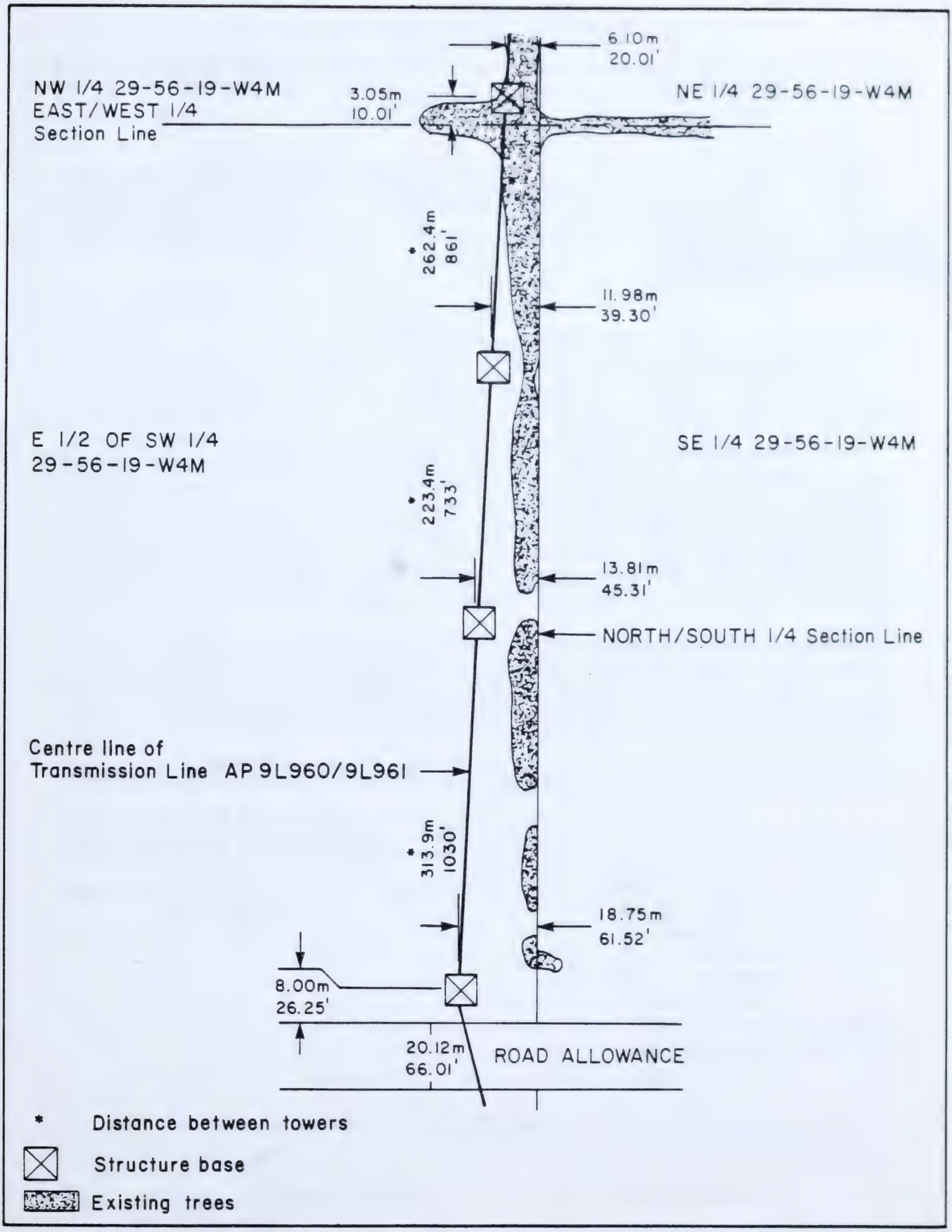
ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

M. J. Bruni
Acting Board Member



TRANSMISSION LINE RE-ROUTE
PROPOSED STRUCTURE LOCATIONS

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY FEDERATED PIPE LINES LTD.
TO CONSTRUCT A PIPELINE AND RELATED FACILITIES
BONNIE GLEN TO ACHESON

Decision D 87-13
Application 870677

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OCT 13 1987

1 APPLICATION AND HEARING

Federated Pipe Lines Ltd. (Federated) applied for a permit to construct approximately 66 kilometres (km) of 168.3-millimetre (mm) outside diameter (OD) pipeline (the proposed pipeline) to allow transportation of high vapour pressure (HVP) products from the Texaco Canada Resources (Texaco) Bonnie Glen gas plant located in legal subdivision 5 of section 17, township 47, range 27, west of the 4th meridian, to a recently-constructed Federated pipeline terminated near Acheson in Lsd 6-2-53-26 W4M. The route of the proposed pipeline is shown in Figure 1. The general purpose of the applied-for pipeline would be to complete an HVP pipeline link between West Pembina, Brazeau, and related areas, through West Edmonton to Swan Hills. Applications for reversal of flow in some of the existing pipelines would be needed.

A public hearing of the application was held on 28 and 29 July 1987 in the Sandhills Community Hall near Edmonton, Alberta, with N. A. Strom, P.Eng. (Chairman), C. J. Goodman, P.Eng., and J. P. Prince, Ph.D., sitting. Participants at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Federated Pipe Lines Ltd. (Federated) R. M. Perrin	R. T. Argument, P.Eng. W. A. Jackson, P.Eng. J. Komisar M. J. Massecar, P.Eng. B. W. Peterson D. F. Mutrie (of Tera Environmental Consultants (Alta.) Ltd.)
Chevron Canada Resources Limited (Chevron) N. J. Strantz	R. M. Shaunessy, P.Eng.
Home Oil Company Limited (Home) H. L. Hooker	D. M. Brown

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
L. B. Erikson	L. B. Erikson
Parkland Rural Residents Association (PRRA) E. Fitzgerald P. A. Young	E. Fitzgerald P. A. Young
T. Morrison	T. Morrison
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff T. J. Pesta, P.Eng. B. Burgess	

Conoco Canada Limited, Gulf Canada Resources Limited, Sulpetro Limited (in receivership), and Texaco Canada Resources filed written submissions in support of the application but did not appear at the hearing.

Edmonton Metropolitan Regional Planning Commission also filed a submission listing eleven pipeline route selection criteria, including use of corridors, that it recommends for the Edmonton Metropolitan area, and raised three secondary questions relating to potential reduced right of way and reclamation seeding. However, it did not take issue with the route chosen by the applicant, nor did it appear at the hearing.

2 VIEWS OF THE PARTICIPANTS

2.1 Federated

Federated stated that there is a need for the pipeline because surplus Natural Gas Liquids (NGLs) in the general West Pembina/Brazeau area will evolve as miscible flood demand in that area declines. As well, additional field ethane extraction facilities in these areas, and other areas in proximity to the proposed pipeline, have been approved or applied for. Meanwhile, additional supplies of ethane and ethane-plus solvent will be required for Phase II of the Swan Hills Unit No. 1 miscible flood, scheduled for start-up on 1 May 1988. Federated entered into an agreement with Texaco whereby Federated would assume operation of the existing Texaco Cynthia pipeline that connects the West Pembina/Brazeau area to the Bonnie Glen plant. Federated stated that there are limitations in throughput capacity of existing NGL pipelines emanating from West Pembina, and that its proposed pipeline, in conjunction with existing pipelines and facilities, would provide a flexible transportation system from West Pembina and related areas to the miscible floods at Swan Hills or other markets centred on Fort Saskatchewan.

Federated listed five key guidelines it endeavoured to meet in selecting an optimum route for the pipeline. Although there are no minimum separation distances established for HVP pipelines, it endeavoured to maintain a minimum distance of 200 metres (m) from residences and 1000 m from heavily populated areas. In addition, to minimize interference with existing and future land use, it endeavoured to locate routes adjoining and parallel to existing pipeline rights of way, quarter-section lines, and other linear developments where feasible.

Federated examined the possibility of alternative routes around Wizard Lake and through the Transportation/Utility corridor of the Restricted Development Area (RDA) on the south and west sides of Edmonton. It also looked at shifting the route 2.4 km west in the general Woodbend-Graminia area. It concluded that the Wizard Lake optional routes would incur increased cost, would not adhere to the corridor concept, and had some environmental disadvantages. The RDA alternative was inappropriate as it would encroach on densely populated areas within the city of Edmonton. The shift in the Woodbend-Graminia area did not seem warranted since it would increase the number of residences in proximity to the pipeline.

Respecting technical matters, Federated stated that, although the entire pipeline route is designated a Zone 1* location in accordance with Canadian Standards Association code CAN3-Z183-M1986, Oil Pipeline Systems (CSA), the portion of the pipeline north of the North Saskatchewan River would be designed to meet the stricter Zone 2** requirements. Compared to Zone 1, these include deeper pipeline burial, closer sectionalizing valve spacing, greater pipeline wall thickness, and a higher hydrostatic test pressure. In response to questions, Federated emphasized that it has operated its existing HVP pipeline system without incident, and that it is confident that the proposed pipeline can and would be operated safely.

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* A Zone 1 location is an area extending 200 m on either side of the centreline of any continuous 1 km length of an HVP pipeline that contains five or fewer dwelling units intended for human occupancy.

** A Zone 2 location is an area extending 200 m on either side of the centreline of any continuous 1 km length of an HVP pipeline that contains more than five dwelling units intended for human occupancy or a facility that contains 20 or more persons during normal use.

2.2 Industry Interveners

Chevron and Home intervened in support of Federated's application. Chevron operates nine miscible floods in the West Pembina, Brazeau, and Bigoray areas. It stated that as the miscible floods in those areas mature there will be a need for transportation of NGLs out of the area. The proposed integrated Federated system would allow transportation of these products to the existing Federated pipelines connecting Fort Saskatchewan to Swan Hills and Mitsue.

Home, as operator of the Swan Hills Unit No. 1 miscible flood, stated it required additional NGL volumes for the recently-approved Phase II of the flood. Home is responsible for obtaining almost 50 per cent of the solvent requirements and believed that the proposed pipeline is the only system that would provide security of supply and ensure the transportation of working interest owner proprietary products under commercially favourable terms.

Conoco Canada Limited, Gulf Canada Resources Limited, Sulpetro Limited, and Texaco Canada Resources filed submissions in support of the application, but did not appear at the hearing. In addition, Federated submitted letters of support from Petro-Canada Resources, Encor Energy Corporation Inc., and Amerada Minerals Corporation of Canada Ltd.

All industry interveners stated that there is a need for Federated's proposed pipeline system.

2.3 Dr. Erikson

The proposed pipeline would be built across a quarter-section of land bordering on Wizard Lake, and owned by Dr. L. B. Erikson. Dr. Erikson opposed the lake crossing and stressed that the reputation of the lake as a recreational area would suffer if a pipeline rupture occurred in the lake. He felt that a study of the Wizard Lake area should be conducted to determine its level of environmental sensitivity as a prerequisite to possible approval of the proposed Wizard Lake crossing. Dr. Erikson contended there are already too many pipelines crossing his property, and that an additional pipeline adjacent to the existing ones is not desirable. He argued that if it were necessary for the pipeline to cross his property, he would prefer it located on a lower, less usable portion of land on the east side of his quarter-section.

2.4 PRRA

The PRRA expressed concerns that the proposed pipeline route passing through the Woodbend-Graminia area and through West Edmonton would serve to establish a pipeline corridor. It wanted any decision on Federated's application deferred until studies could be conducted in co-ordination with all planning authorities to establish an optimum corridor route.

PRRA also had concerns about the safe design and operation of the proposed pipeline and recommended that

- a block valve be installed at SW 1/4-23-51-27 W4M to reduce block valve spacing to 7.5 km in that area; (This was agreed to by Federated prior to the hearing.)
- consideration be given to installing four additional block valves, perhaps manually operated, one in the vicinity of the Graminia School and three near municipal road crossings;
- consideration be given to conducting weekly aerial inspections of the right of way during periods of the year when construction programs are most active;
- the pipeline location be identified by markers located so as to be visible from each neighbouring marker;
- Federated discuss its emergency response plans with members of the community;
- all industry and local authority emergency response plans be co-ordinated.

2.5 Mr. Morrison

In general, Mr. Morrison supported the intervention presented by the PRRA. In addition, he expressed concern about the reliability of the systems and equipment on the proposed pipeline, and specifically recommended that a detailed engineering reliability analysis be performed. Mr. Morrison also questioned whether all of the impacts on the community were considered, and believed that a real cost-benefit analysis should be performed.

3 ISSUES

The Board considers the issues to be

o the purpose and necessity of the pipeline,

o the need to establish a utility corridor,

o local route selection issues,

o safe design, emergency response, and impact on the community.

3.1 Purpose and Necessity of the Pipeline

Federated has received requests from producers to provide an integrated transmission system capable of collecting NGLs produced at plants in the

West Pembina/Brazeau area and other related areas, and delivering these NGLs to the Acheson, Swan Hills, Mitsue, Nipisi, and other miscible flood projects, or alternatively to centralized storage and other facilities in the vicinity of Fort Saskatchewan. Completion of the proposed pipeline would achieve those purposes. Federated expected that by 1993 it would be necessary to reverse the flow in the Namao/Fort Saskatchewan segment to permit movement of NGLs into storage at Fort Saskatchewan. If NGLs are required in Fort Saskatchewan prior to that time, a pipeline connection between Namao and Fort Saskatchewan may be required.

None of the interveners questioned the purpose and need for the pipeline. The industry interveners argued that the proposed pipeline would provide a valuable integrated transmission system.

The Board agrees that the proposed Bonnie Glen to Acheson HVP pipeline link is a logical addition to serve the industry's expressed needs.

3.2 Need to Establish a Utility Corridor

This section of the report will deal with the need to establish a pipeline corridor to accommodate the applied-for pipeline and any future pipelines that may be expected to traverse the same area to serve major industrial users.

Pipeline corridors provide the advantage of confining linear developments and thereby concentrating land use impacts and avoiding proliferation over many areas. There are two broad categories of pipeline corridors; the first involves the pre-establishment of a corridor to accommodate future pipeline developments and facilitate land use planning. Examples of this would be the Edmonton RDA incorporating transportation/utility corridors around major urban centres, and the pipeline-dedicated corridor established as a result of the ERCB's Northeast Edmonton Pipeline Corridor Inquiry. The second category is more local in nature and derives from a practice recommended by planning authorities of placing new pipeline rights of way adjacent to existing ones where feasible. This approach assists in confining land use impacts but does not constitute establishment of a dedicated corridor. For the great network of pipelines criss-crossing the province, this is the most common means of reducing pipeline land use impacts.

The PRRA expressed concerns that Federated's proposed route would become the basis for a future corridor for other pipelines requiring access to the West Edmonton area. It inferred that future pipelines would be needed to transport products through the same areas, as the petroleum and petrochemical industries continued to grow. PRRA therefore recommended that the Federated application be deferred until such time as planning authorities, in conjunction with the public, could thoroughly assess the most appropriate route for a utility corridor including that near the country residential areas south and west of

Edmonton. It questioned whether the Federated preferred route would be a desirable location for a pipeline corridor since it does not explicitly consider the long-term implications in land use planning.

Federated argued that its proposed HVP pipeline would be adequate to serve the purpose of moving all required quantities of NGLs from the West Pembina area and other related areas to the desired miscible flood destinations and the Fort Saskatchewan petrochemical region. It did not comment on future resource activity requiring additional pipelines.

The Board notes that in the ERCB Post-Inquiry Progress Review, September 1980, of the Mill Woods Pipeline Inquiry, the ERCB endorsed the concept of pipeline corridors as a means of satisfying the compatibility of pipelines and urban growth. Also, in its "Information Requirements for Regulated Pipelines" (1982), Alberta Environment encourages, wherever possible, the parallelling of existing rights of way, and the Edmonton Metropolitan Regional Planning Commission utilizes very similar guidelines respecting pipelines and powerlines.

The Board notes that Federated's Bonnie Glen to Acheson HVP pipeline will provide an integrated pipeline linkage to move NGLs to or from a network of several of Alberta's major oil and gas fields located in Western, Central, and Northern Alberta. Also, this pipeline system would have a tie, in the future, to the major petrochemical complexes near Fort Saskatchewan. These facts lead the Board to conclude that there is some future possibility of expansion of the Federated integrated pipeline system or for other pipelines which would trace the same route in order to traverse the West Edmonton semi-urban area. If that should occur, a de facto minor pipeline corridor would come into existence. The routing criteria used by Federated which conform with planning guidelines would enhance that possibility. At the same time, it is noteworthy that landowners on the selected route in the West Edmonton area did not raise concerns or objections.

Taking all factors into account, the Board concludes that there are no substantive reasons to hold an inquiry in order to pre-establish a designated pipeline corridor for the West Edmonton area, and the Board does not accept the PRRA proposal to defer consideration of the Federated application pending such an inquiry.

3.3 Local Route Selection Issues

Federated was questioned on its preferred and alternative routes through two specific areas: Wizard Lake and the Woodbend-Graminia country residential areas north of the North Saskatchewan River.

3.3.1 Wizard Lake

Federated demonstrated that the applied-for route which crosses Wizard Lake adjacent to seven existing pipelines is significantly shorter than alternative routes around the lake, and that it is therefore more cost-effective. In response to a proposal by Dr. Erikson, the applicant argued that a Wizard Lake crossing approximately 800 m to the east of the proposed crossing near the east section line of the NW 1/4-3-48-27 W4M would not be acceptable since it would not adjoin existing crossings, would be located closer to existing residences and to a proposed residential development on the south bank, would be approximately 130 m longer on the lake bottom, and would be approximately 1600 m longer in overall length. In addition, the route would traverse shallow coal mines, and would not provide a convenient staging point for pre-assembly of the lake crossing. Federated stated that the existing pipelines crossing Wizard Lake do not impact on the recreational use of the lake. It stated that its proposed pipeline would be coated with 50 centimetres (cm) of concrete to submerge and further protect the pipe. Federated believed that the possibility of a leak occurring in the water crossings is remote. However, it stated that should a leak occur, the product would be released as a vapour which would rise to the surface and escape into the atmosphere. It noted that due to the low solubility of NGLs in water, no adverse effects on water quality, water chemistry, or aquatic life would occur. Federated stressed that pipeline transportation of HVP products has a very good safety record and that the probability of a leak is very low.

Dr. Erikson expressed considerable opposition to the route of the pipeline across Wizard Lake. He stressed the importance of Wizard Lake as one of the better recreational use lakes in the province and was concerned about the loss of public enjoyment in that use if a pipeline failure should occur. He was not convinced that the pipe could be successfully coated with concrete. He contended that the proposed pipeline should be re-routed around the lake and that the incremental cost of such a route would not represent a large encumbrance to Federated or its customers. He noted that there are a number of pipelines already crossing Wizard Lake and his property, and questioned whether there would be an upper limit to the number of pipelines that would be allowed to cross the lake.

Alberta Environment questioned the applicant on the specific necessity for parallelling existing pipelines across Wizard Lake and questioned Federated on the possibilities of routing the pipeline around the west end of Wizard Lake. Federated pointed out that in order to follow its routing guidelines and to avoid proximity to a proposed County of Wetaskiwin Park, such a route would be 6 km longer than its selected route.

In the Board's view, the key question is whether public enjoyment of Wizard Lake as a recreational lake would be significantly impaired by the presence of the proposed HVP pipeline. The Board understands that the application of a 50-cm reinforced concrete sheath for the 200-m pipeline section across the lake will provide reliable protection of the pipe during installation and later operation. As well, valves will be placed at each end of the crossing so that any pipeline rupture in the lake would be a very short-term event with release of only a small quantity of HVP product. As well, because of design precautions, the lake crossing and river crossing are the places least likely to experience any such failure. Taking these factors into consideration, along with the overall design and operational safety features of the system, the possibility of a pipeline rupture in the lake would seem to be very remote. Indeed, the absence of problems with the existing pipelines in the lake, some of which have been there for over 20 years, strongly support that conclusion. In terms of recreational enjoyment, therefore, the only negative factor appears to be the public's perception of a prospect for such a failure. In this regard the pipeline operator, as well as other operators, plus regulatory authorities, have a continuing role of informing the public respecting the high degree of protection provided.

The Board concludes that, while it would not be averse to requiring the routing of the pipeline around the lake even if the costs were higher, safety reasons do not justify that conclusion. The Board holds that perceptions of safety and concerns about future enjoyment of the lake warrant more direct information and communication to correct any misconceptions that may exist. Regarding Dr. Erikson's concern about excessive numbers of pipelines crossing his lands, this is clearly a consequence of application of the corridoring concept which is widely favoured by planning authorities. Accepting the advantages of corridoring, the issue appears to be one of suitable compensatory arrangements where a particular landowner is repeatedly affected by additional pipelines. However, it is not within the jurisdiction of the ERCB to deal with that issue.

The Board concludes that the applied-for crossing is technically sound and should be granted.

3.3.2 Woodbend-Graminia

Federated compared its preferred route with a shift to a western alternative route (illustrated in attached Figure 2) through the country residential areas north of the North Saskatchewan River. The western alternative route would be 2.2 km longer than the proposed route. In addition, although it would increase the separation from the Graminia School from 1.2 km to over 2.5 km, the line would then pass within 200 m of thirteen existing residences in comparison to eight existing residences on the proposed route.

The PRRA did not object to routing of the pipeline through the country residential areas, although it was concerned about proximity to the Graminia School. It believed that there may be more feasible routes; however, it concluded that the pipeline would similarly affect residents irrespective of its location. Its main concern regarding the route was that a pipeline corridor not be created in the location of Federated's proposed pipeline.

The Board notes that guidelines for setbacks of HVP pipelines from public institutions (for example, hospitals and schools) call for a minimum separation distance of 200 m. The separation of 1.2 km from the school is more than ample, and the Board finds no valid reason to further increase that separation distance.

3.4 Safe Design, Emergency Response, and Impact on the Community

Federated summarized the safety features which would be incorporated into the proposed pipeline system. It stated that even though all of the pipeline is designated as a Zone 1 area, it has designed the portion of the pipeline north of the North Saskatchewan River to the stricter Zone 2 area requirements. Federated further noted that an additional remotely activated block valve would be installed in the SW 1/4-23-51-27 W4M, at the request of the PRRA, thereby halving the Zone 2 required valve spacing through the country residential areas. Furthermore, even though there are no regulations requiring a minimum separation distance from residences, Federated had used a guideline of 200 m.

Federated stated that its existing leak detection system, which meets or exceeds the requirements of the latest edition of the Canadian Petroleum Association Recommended Practice for Liquid Petroleum Pipeline Leak Prevention and Detection for HVP pipelines, would be expanded to include the proposed pipeline. Upon indication of a leak, the pipeline would be shut down and block valves would be activated to isolate the leak. Federated was not familiar with the equipment used on the pipeline in the Mill Woods area; however, it noted that Federated has not encountered problems with the operation of valves on its pipelines and stressed that all equipment is regularly maintained to ensure dependable service.

Federated's existing Emergency Response Action Manual and Maintenance Procedures Manual would be revised to include sections pertaining to the proposed pipeline. Federated undertook to consult with residents after a draft plan has been developed, and to consider their comments.

Federated proposed to conduct internal electromagnetic pipeline surveys at approximately 5-year intervals; however, it believed that the performance of a baseline survey would not be necessary to assist in the correlation of future surveys. It argued that it is confident that the proposed pipeline would be installed without significant defects and that all unusual occurrences indicated by future surveys would be investigated by immediate inspection of the pipeline.

Federated proposed to conduct bi-weekly helicopter patrols of the pipeline right of way and weekly line-of-sight ground patrols. It argued that weekly helicopter patrols would not be necessary. To PRRA's recommendation that pipeline markers be installed so that the next marker is visible from the previous marker and at sufficient intervals along the pipeline to accurately mark the pipeline location, Federated suggested that it would be dangerous to install markers in the middle of cultivated fields. Federated noted that it maintains a public awareness program to minimize the potential for damage to the pipeline.

PRRA suggested various modifications for the purposes of improving the safety of the pipeline and the response to a leak. In addition to a valve near the Graminia School, PRRA requested manual block valves at three road crossings. It argued that additional block valves would reduce the volume of product between block valves and that this would alleviate residents' apprehensions of a potential disaster. The PRRA also requested weekly aerial inspection of the pipeline during active construction periods. It suggested that this frequency is necessary to reduce the potential for damage to the pipeline resulting from unauthorized activities near the pipeline. Furthermore, PRRA believed that spacing of pipeline markers to accurately reflect changes in direction of the pipeline, and so that consecutive markers are visible from the previous marker, would be of benefit in reducing the potential for damage to the pipeline. It suggested that in its area of concern, farming activities are not prevalent; therefore, locating markers away from section lines would not pose a problem.

With respect to an emergency response plan, PRRA stressed that the preparation of the plan must be co-ordinated with the community to ensure that all unique features of the area are considered. It suggested that the list of residents should be compiled for the area within 1600 m of the pipeline, not 800 m as proposed by Federated, so that residents outside of the 800-m area could also be alerted if necessary. Moreover, PRRA contended that it would seem reasonable that all parties with emergency response plans co-ordinate those plans with one another. The PRRA was satisfied with Federated's undertaking to provide the draft of its emergency response plan to the community for comments.

Mr. Morrison enquired as to the differences between the design of the proposed pipeline and that which ruptured in the Mill Woods area. He suggested that malfunctioning equipment on the pipeline in the Mill Woods area was a contributing factor to the incident. For this reason he strongly believed that Federated should perform a detailed reliability analysis on all of the equipment and that the results of such an analysis be utilized in the formation of an emergency response plan.

Mr. Morrison stressed that in addition to the potential benefits of the proposed pipeline, serious consideration must be given to the negative impacts on the community. In his view, these negative impacts would be, among other things, the need for additional fire-fighting capabilities and the increased cost of road maintenance due to industrial activity. Mr. Morrison believed that a real cost-benefit analysis must be performed to accurately determine what the impacts would be.

Views of the Board

The Board notes that the proposed pipeline north of the North Saskatchewan River was designed to meet or exceed Zone 2 requirements, that Federated would install a remotely operated valve in the SW 1/4-23-51-27 W4M at the request of PRRA, and that Federated has established a guideline of a 200-m setback from residences.

The Board accepts that additional manual block valves, as proposed by PRRA, would provide opportunities to reduce the gross quantity of a fluid release from a pipeline rupture in that vicinity. However, it is not convinced that such additional block valves would significantly reduce the size of the rupture vapour cloud. The Board believes that the product release would quickly reach an equilibrium between low-concentration vapour dissipation into the atmopshere and the rate of fully concentrated fluid escaping from the pipeline. At that point the size of a vapour cloud becomes more or less constant. Attempting to reduce the potential overall quantity and duration of release through added manual valves over and above those called for by the pipeline safety codes appears to be of questionable merit.

With respect to the reliability of block valves and other critical equipment, the Board understands that Federated would meet or exceed the requirements of the CSA standards and that the pipeline would also be designed in accordance with the Pipeline Regulation. These requirements do not call for the performance of a reliability analysis; however, reliability considerations have been incorporated into the standards and the regulations. Past performance of many systems has clearly demonstrated that pipelines are reliable when designed, constructed, and operated in accordance with these standards and regulations. Reliability can be achieved without performance of the reliability analysis requested by Mr. Morrison, and the Board is satisfied that the existing standards and regulations are adequate.

Federated suggested that an internal electromagnetic pipeline survey would be performed at approximately 5-year intervals with the first survey 5 years after construction. Generally the Board accepts this frequency but considering the likelihood of semi-urban development and construction activity in the vicinity of the proposed pipeline, the Board believes that an early survey should be conducted. Should the Board approve the pipeline, it would require that a survey be performed within the first year of operation.

Respecting PRRA's recommendations concerning pipeline markers, the Board recognizes the PRRA's intent to minimize the danger associated with construction or other activities on or near the pipeline right of way. However, it notes that Federated's practice of maintaining yearly contact with residents within 800 m of the pipeline would serve to remind area residents of the location of the pipeline right of way, thereby reducing the risk of unauthorized activities occurring on the right of way. Therefore, the Board believes that established requirements for the marking of pipelines are sufficient. However, the Board would expect Federated to ensure adequate marking based on actual field conditions encountered. Similarly, while the Board accepts Federated's proposed frequencies of visual inspections of the right of way, it would expect Federated to intensify surveillance whenever construction or related activities by other parties was occurring near its pipeline.

The Board notes that PRRA accepted Federated's proposal to provide for community involvement in the preparation of the emergency response plan. Should the Board approve the proposed pipeline, it would request that Federated provide a copy of the draft emergency response plan to PRRA for review with sufficient lead-time to permit the review and finalization of the plan prior to operation of the pipeline.

The Board believes that the various municipalities and counties also have a responsibility to assess the impact of the proposed pipeline and, since they did not submit a position at the hearing, the Board assumes that they did not consider the potential impact significant. The Board concludes that a detailed study of impacts by other parties is not warranted.

4 DECISION

Having carefully reviewed the evidence and arguments, the Board approves the pipeline as applied for but subject to those conditions and modifications noted in this report.

The permit will be issued upon receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act.

DATED at Calgary, Alberta, on 1 October 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member

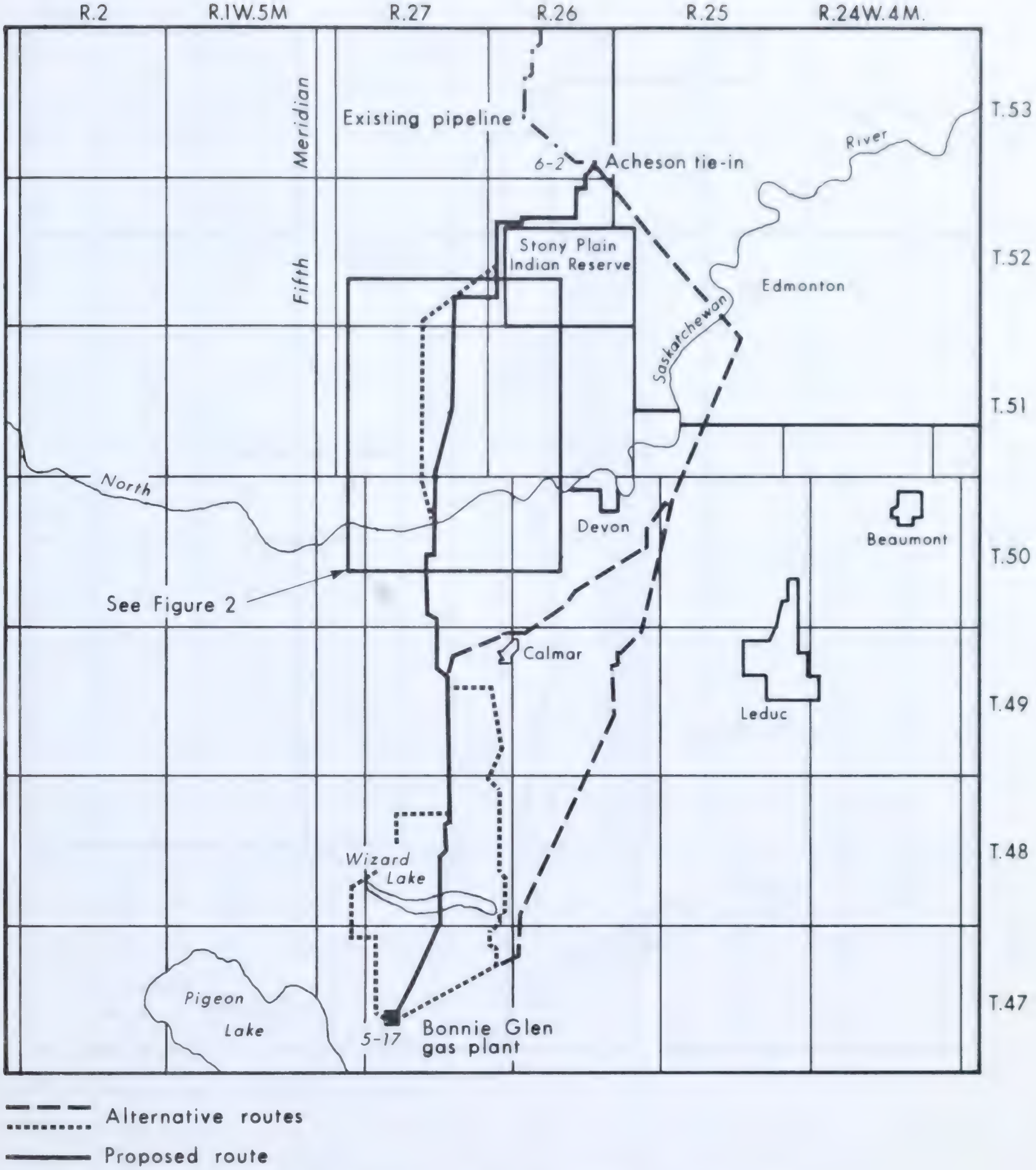

FIGURE 1 PROPOSED BONNIE GLEN-ACHESON PIPELINE AND ALTERNATIVE ROUTES DISCUSSED
Federated Pipe Lines Ltd.
Application No. 870677

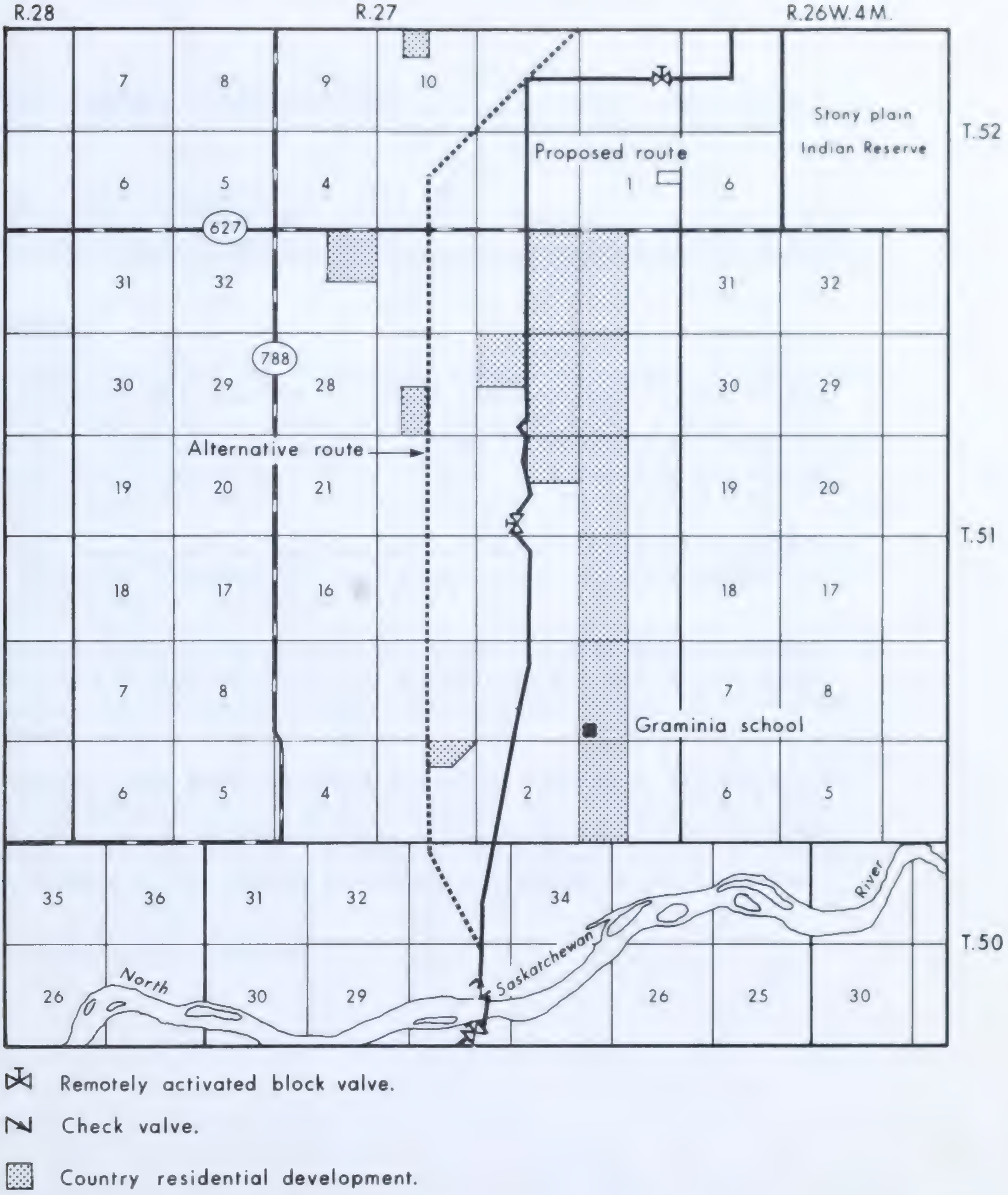

FIGURE 2 PROPOSED BONNIE GLEN – ACHESON PIPELINE AND ALTERNATIVE ROUTES DISCUSSED.
Federated Pipe Lines Ltd.
Application No. 870677

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY FEDERATED PIPE LINES LTD.
TO CONSTRUCT A PIPELINE AND RELATED
FACILITIES - BONNIE GLEN TO ACHESON

Addendum to Decision D 87-13
Application 870677

Background

Federated Pipe Lines Ltd. (Federated) applied for a permit to construct approximately 66 kilometres of 168.3-millimetre (mm) outside diameter (OD) pipeline from the Texaco Canada Resources Bonnie Glen gas plant located in legal subdivision 5 of section 17, township 47, range 27, west of the 4th meridian (5-17-47-27 W4M), to a recently-constructed Federated pipeline terminated near Acheson in Lsd 6-2-53-26 W4M.

A public hearing of the application was held on 28 and 29 July 1987 in the Sandhills Community Hall near Edmonton and the Board issued its decision in Board Decision D 87-13 on 1 October 1987.

Federated subsequently informed the Board of a discrepancy between Federated's design intentions and its written and hearing testimony regarding the continuous concrete coating thickness for the Wizard Lake crossing.

Accordingly, the Board re-opened the public hearing of the application at the Board's offices on 12 November 1987, with N. A. Strom, P.Eng. (Chairman), C. J. Goodman, P.Eng., and J. P. Prince, Ph.D., sitting to consider evidence directly relating to the concrete coating thickness. Participants at the hearing re-opening are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Federated Pipe Lines Ltd. (Federated) C. Keck	R. T. Argument, P.Eng. M. J. Massecar, P.Eng.
Chevron Canada Resources Limited (Chevron) N. J. Strantz	
L. B. Erikson	L. B. Erikson
T. Morrison	T. Morrison
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff T. J. Pesta, P.Eng. B. Burgess C.J.C. Page	

The Parkland Rural Residents Association and Home Oil Company Limited did not appear at the hearing re-opening.

Views of Federated

Federated stated that its staff used the correct units, ie. millimetres, in the design of the concrete coating for the pipeline but that, due to a typographical error, the written submission incorrectly indicated that the concrete coating thickness for the Wizard Lake crossing would be 50 centimetres (20 inches). Furthermore, Mr. Massecar was thinking of millimetres when questioned at the hearing. Federated stressed that a 25-mm (1-inch) concrete coating is the thickness normally used to ensure that an empty 168.3-mm OD pipeline with 6.35-mm wall thickness does not float. To provide additional protection from third-party damage, Federated intended, and still intends, to double the normal concrete coating thickness to 50 mm (2 inches), and to still include the wire mesh used to reinforce the concrete coating.

Federated described impact tests performed on the concrete coating by the manufacturer which verified that the concrete coating is very resistant to impact, and that 50-mm thickness is more than sufficient for the protection of the pipe from an object such as a boat anchor being dropped on or dragged across it. Federated also described pipe laying methods which would ensure that the pipe did not overlap other existing pipelines or encounter lake bottom features which might damage the coated pipe.

Federated suggested that the typographical error could not have carried through unnoticed into the manufacturing process since the planned method of concrete coating manufacture is not suitable for 50-cm thickness, nor would the on-site construction equipment be able to install pipe coated with a 50-cm thickness of concrete coating.

Views of Other Participants

Dr. Erikson accepted the correction of the error in stated concrete coating thickness for the Wizard Lake crossing from the originally stated 50 cm to 50 mm. However, he enquired about the number of existing pipelines crossing Wizard Lake and the locations of those pipelines relative to one another. He queried the applicant respecting the continuing integrity of the concrete coating.

Mr. Morrison pointed out that the public had to rely upon the judgement of professional engineers, including their ensuring that information provided to the public was correct and authentic. While he sympathized with the applicant's difficulties in correcting the erroneous interpretations that had arisen, he continued to be concerned that a ten-fold magnitude of error had managed to pass scrutiny without being detected within the applicant's technical team. He stressed that this magnitude of an error could have serious implications if it happened in a different situation, and suggested that stringent safeguards should be implemented to ensure that such errors do not occur.

Chevron Canada Resources Limited did not take issue with the proposed correction of the stated concrete coating thickness.

Decision

The Board shares Mr. Morrison's concern about the occurrence of this error. Not only was incorrect information submitted to the Board, but it was reconfirmed in the hearing testimony. Federated may well be correct in its assertion that in this case the error would have inevitably been found, but what if the reverse had been true and an inadequate coating had been inadvertently presented, defended, approved, and installed? The Board wishes to emphasize unequivocally that accurate and understandable communications are essential and that it is absolutely necessary for all documents to be free of errors. The responsibility to see that a proposal is error-free, including free of typographical errors, rests with the professional who adopts the proposal as his or her evidence.

The Board has considered the proposed correction and agrees that a 50-mm concrete coating thickness on the pipeline section across Wizard Lake would ensure that the pipeline would not float. Although an order of magnitude less than originally stated, a reinforced 50-mm layer would provide satisfactory protection of the pipe on the lake bottom.

Consequently, the Board accepts the correction of the concrete coating thickness to 50 mm and, subject to this correction, the Board reconfirms its decision issued in Board Decision D 87-13.

DATED at Calgary, Alberta, on 20 November 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ALBERTA POWER LIMITED
ALBERTA-SASKATCHEWAN INTERCONNECTION
EMPRESS AREA

Decision D 87-14
Application 870308

1 APPLICATION AND HEARING

1.1 Application

Alberta Power Limited (Alberta Power) applied to the Energy Resources Conservation Board (ERCB), pursuant to sections 12, 13, 14, 15, 16, and 17 of the Hydro and Electric Energy Act, for permits, licences, and orders

(a) to construct and operate a direct-current (DC) back-to-back converter station near Empress, Alberta, to be called McNeill DC Converter Station 840S, with a maximum power transfer capability of 100 MW in either direction;

(b) to construct and operate a 138-kV single-circuit transmission line, designated 830L, from the existing Dome Empress substation 163S to McNeill DC Converter Station;

(c) to construct and operate a 230-kV single-circuit transmission line, designated S1M, from the McNeill DC Converter Station to the Alberta-Saskatchewan border;

(d) to connect the proposed 138-kV transmission line and McNeill DC Converter Station to TransAlta Utilities Corporation's Dome Empress substation;

(e) to interconnect the proposed 230-kV transmission line and McNeill DC Converter Station with the electric system of Saskatchewan Power Corporation (Saskatchewan Power) at the Alberta-Saskatchewan border; and

(f) to make certain alterations to the existing Dome Empress substation 163S and 138-kV transmission line 760L.

The proposed facilities and their locations are shown on the attached figure.

The proposed 138-kV transmission line would be built on road allowance on the right of way of an existing 25-kV line, which would then be understrung on the new structures. The line would be approximately 8.7 km in length and would be owned and operated by TransAlta Utilities Corporation. The proposed McNeill DC Converter Station would be located on Crown land and would be owned and operated by Alberta Power. The 230-kV single-circuit transmission line would be approximately 1.6 km long and built on H-frame double wood-pole structures. The line would be owned and operated by Alberta Power and would be located on Crown land.

The precise location of the 230-kV line to be built by Saskatchewan Power from the border to Swift Current has not yet been determined. Although the exact routing of the section of the line within Alberta cannot be determined at this time, it will be located within a designated corridor shown in the attached figure. Alberta Power expects to file details of the exact line route within that corridor by November 1987.

Alberta Power obtained written consents from all landowners within 0.8 km of the proposed lines and converter station. No objection to construction of the proposed facilities was filed by any of the local landowners/occupants.

Alberta Power stated that it had requested potential manufacturers of the converter station to bid on the basis of interconnection sizes of 100 MW and 150 MW. Although this application is for approval of 100-MW converter station capacity, Alberta Power stated that it may ask the Board to amend the interconnection to a capacity of 150 MW, if its evaluation of the bids found it to be more economic.

The successful bidder for the converter station facilities would be required to conduct studies to determine the characteristics of the converter station equipment and its potential effects on the area loads, and to determine any necessary mitigative measures. Measures would also be taken to mitigate any effects of the proposed interconnection on the operation of Alberta Government Telephones' facilities in the area.

Alberta Environment and other government agencies did not express any concerns with the proposed project.

1.2 Hearing

A public hearing to consider the application was held in Calgary on 25 August 1987, with C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and J. P. Prince, Ph.D., sitting. Those who appeared at the hearing are listed in the following table.

PARTICIPANTS AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Power Limited (Alberta Power) C. K. Sheard	J. R. Frey, P.Eng. W. J. Beckett, P.Eng. R. V. Baer, P.Eng. M. C. Swales, P.Eng.
Industrial Power Consumers Association of Alberta (IPCAA) A. L. McLarty	
TransAlta Utilities Corporation (TransAlta) J. B. Malone	
Electric Utility Planning Council (EUPC) G. N. McDermid, Q.C.	
Alberta Environment D. Bratton	
Energy Resources Conservation Board staff A. Broughton M. L. Asgar-Deen, P.Eng. A. Kwaczek S. S. Lota, P.Eng.	

IPCAA, TransAlta, and the EUPC registered and participated at the hearing but did not submit any direct evidence.

2 JUSTIFICATION FOR THE PROPOSED INTERCONNECTION

2.1 Views of the Applicant

Alberta Power stated that the primary reason for building the proposed interconnection at this time is the need for additional reserve generating capacity by Saskatchewan Power beginning in 1989. The main benefit of the proposed interconnection to the Alberta interconnected electric system (AIS) would be the permanent displacement of 100 MW of peaking/reserve capacity required in the future. Based on the 1985 EUPC load forecast, this need for peaking capacity on the AIS could occur as early as 1995. Alberta Power argued that, beginning in 1995, the interconnection would provide a source of reserve generating capacity to both Saskatchewan Power and the AIS. Other potential benefits to the AIS would include

(a) possible surplus power sales from the AIS to Saskatchewan Power and the United States via Saskatchewan Power's system;

(b) an additional source for purchases from time to time of economy energy to displace higher incremental cost AIS energy;

(c) an improved negotiating position for the AIS for sale to or purchase of surplus energy from British Columbia Hydro and Power Authority; and

(d) transmission operating flexibility in southern Alberta.

An interconnection agreement has been signed by Alberta Power and Saskatchewan Power which places certain obligations on both parties for a period of 25 years. The agreement stipulates that, since the AIS would not require additional generating capacity until at least 1995 (beyond the completion of Sheerness and Genesee generating plants), Saskatchewan Power would pay all carrying costs associated with the interconnection facilities in both Saskatchewan and Alberta until the end of 1994.

Alberta Power estimated the capital cost of the facilities to be built in Alberta to be $28.2 million dollars (as spent dollars). The cost of facilities to be built in Saskatchewan, from the border to Swift Current, was estimated to be about $13 million. The depreciated cost of the facilities in Alberta was estimated to be $24 million at the beginning of 1995. Alberta Power stated that the depreciated cost, along with operating costs, would be borne by AIS customers beginning in 1995.

Alberta Power assumed that the displaced peaking capacity would have been supplied by a 100-MW combustion turbine, at a cost of $35 million (1986). It performed an economic analysis which compared the costs, to Alberta, of the proposed interconnection as an alternative to a combustion turbine. The results indicated a net benefit to the AIS if the displacement were to occur before the year 2010. Calculated benefit/cost ratios on a present worth basis ranged from 2.3 for displacement in 1995 to 1.0 for displacement in 2010. In its economic analysis, Alberta Power assumed a general inflation rate of 5 per cent and a nominal discount rate of 11.3 per cent. In calculating the benefit/cost ratios, Alberta Power also excluded all other potential benefits identified earlier, although it believed there was a high probability that many of these would materialize. It indicated that over a period of 25 years, the present value of surplus energy sales alone would be a minimum of about $3 million to the AIS.

Alberta Power argued that the need for reserve generating capacity by Saskatchewan Power in 1989 presents a window of opportunity that may not occur again. In view of the above-mentioned quantifiable and unquantifiable benefits, the proposed interconnection is in the public interest. It also expressed the view that historically the worth of an interconnection has always been more than the benefits initially identified.

Alberta Power argued that it has shown that the proposed project is in the public interest. Therefore, any approval issued by the Board should not be conditioned as proposed by IPCAA.

2.2 Views of the Interveners

The EUPC filed a submission at the hearing in support of the application, but did not present any direct evidence.

IPCAA expressed concerns that a combination of construction cost overruns, the selection of a lower load forecast and the selection of other assumptions used in the applicant's economic evaluation could reduce the benefit/cost ratio of the interconection.

Accordingly, it argued that the proposed interconnection represented a considerable risk for higher costs of power to Alberta consumers since it may not be either necessary or in the public interest of Alberta in the 1995 time frame. In the absence of some clear and demonstrable need and equally clear assessment of benefits to Alberta, IPCAA considered it inappropriate for Alberta electric utility customers to bear any risk associated with the project.

IPCAA submitted that it does not oppose approval of the proposed interconnection. However, if the Board decides to approve the project, such approval should be appropriately conditioned to protect the public interest. IPCAA raised several matters which relate to matters of rate base and conditions of service, but acknowledged that these matters are not within the jurisdiction of the ERCB.

2.3 Views of the Board

The Board accepts the rationale and criteria used by Alberta Power in evaluating the benefits of the interconnection. It has examined the impact that various 1986 load forecasts would have on the likely timing of 100-MW combustion gas turbine displacement by the proposed interconnection. The Board is satisfied that the 1986 EUPC 3-year low forecast is a reasonable basis for considering this application and accordingly accepts that capacity displacement could take place as early as 1995. The Board determined that, even using the 1986 ERCB low forecast which is the most pessimistic of the 1986 forecasts, the capacity displacement could still take effect and be economic by the year 2000.

The Board also accepts that several of the other benefits, which Alberta Power identified but did not quantify, are likely to materialize in addition to the main benefit of the proposed interconnection.

The Board notes that present information indicates the AIS would likely have surplus generating capacity between now and 1994. It believes that any opportunity to sell surplus energy or capacity to utilities outside the province would be in the interest of AIS customers.

The Board has also reviewed the technical aspects and locations of the proposed facilities for the interconnection and finds them to be satisfactory. However, it will require Alberta Power to provide the Board with details of the final design and studies relating to performance of the proposed facilities.

In view of the foregoing, the Board believes that the proposed interconnection is in the public interest. It does not consider it appropriate to approve the project subject to conditions regarding matters which are outside its jurisdiction.

4 DECISION

The Board, upon consideration of all the evidence, finds that

(a) the proposed interconnection would be in the public interest; and

(b) the technical aspects and locations of the facilities for the proposed interconnection are satisfactory, subject to the later filing of technical information.

Therefore, the Board is prepared to approve the application for the construction and operation of the facilities as identified in the application. Permits and Licences will be issued for all the proposed facilities except the 230-kV transmission line, the specific location of which is subject to the location of transmission facilities in Saskatchewan and must be determined before approval. Approval for the interconnection will be issued subject to the authorization of the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 30 September 1987.

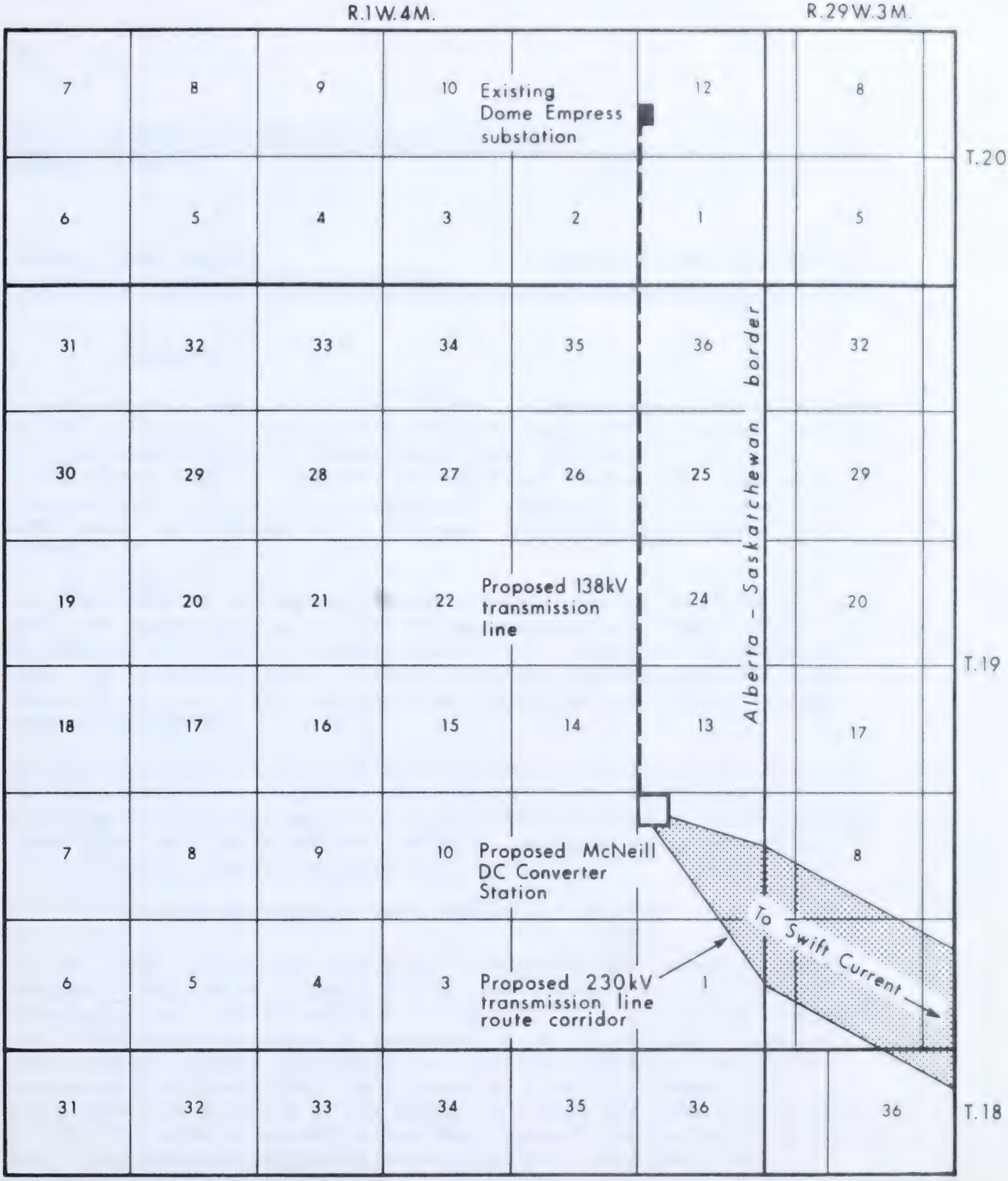
C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member


R.1W.4M.
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Existing Dome Empress substation
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Proposed 138kV transmission line
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Alberta - Saskatchewan border
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Proposed McNeill DC Converter Station
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To Swift Current
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Proposed 230kV transmission line route corridor
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LOCATION OF FACILITIES FOR THE PROPOSED ALBERTA - SASKATCHEWAN DC INTERCONNECTION
Application No. 870308
Alberta Power Limited

D 87-14
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ALBERTA POWER LIMITED
ALBERTA-SASKATCHEWAN INTERCONNECTION

Addendum to Decision D 87-14
Application 870308

1 BACKGROUND

In its original application (No. 870308), Alberta Power Limited (Alberta Power) applied for approval of a 100-MW capacity direct-current facility to interconnect with the Saskatchewan Power Corporation system (Saskatchewan Power). However, Alberta Power stated that, depending upon evaluation of the bids received for supply of the equipment, it might amend its application to increase interconnection capacity to 150 MW.

After considering the application at a public hearing on 25 August 1987, the Board approved the 100-MW interconnection. The Board's reasons are provided in its Decision D 87-14, issued on 30 September 1987. On 14 October 1987, Alberta Power amended its application and asked the Board to amend its decision and approve an interconnection capacity of 150 MW.

At the hearing of the original application, submissions were filed by the Industrial Power Consumers Association of Alberta, TransAlta Utilities Corporation, and the Electric Utility Planning Council. All three interveners have advised the Board that they do not object to Alberta Power's amended application.

2 AMENDMENT TO INCREASE INTERCONNECTION CAPACITY

Alberta Power stated that evaluation of bids for the converter station equipment resulted in a change to the cost estimate for the 100-MW interconnection from $28 million to $32 million. The capital cost of the 150-MW interconnection is estimated to be $36 million. Alberta Power stated that the incremental cost of $4 million for the 150-MW interconnection means that the incremental 50-MW is economically attractive. As a result of the change in costs, the benefit-cost ratio for the 100-MW interconnection has been reduced from the original 2.3 to 2.0. The corresponding benefit-cost ratio for the 150-MW interconnection is 2.2.

Alberta Power stated that its existing interconnection agreement with Saskatchewan Power would be amended such that Saskatchewan Power would pay all carrying costs associated with the 150-MW facilities in Alberta up to the end of 1994. Thereafter, beginning 1 January 1995, each system would rely on the other to provide 125 MW of reserve generating capacity.

3 TRANSMISSION LINE ROUTE

In its original application, Alberta Power stated that it would not be able to finalize the exact route of the 230-kV transmission line from the McNeill DC Converter Station to the Alberta-Saskatchewan border until sometime in November 1987. In its Decision D 87-14, the Board approved the 230-kV line but stated that the specific location of the line would need to be determined before a permit and licence could be issued.

On 29 October 1987, Alberta Power filed details respecting the route of the 230-kV transmission line, as shown in the attached figure. It stated that this route is located within the corridor identified in the original application.

4 DECISION

The Board notes that the incremental cost for a 150-MW capacity interconnection would be small compared to the increase in capacity. That is, a 12.5 per cent increase in capital cost, from $32 million to $36 million, would provide a 50 per cent increase in capacity. It notes that the interconnection agreement between Alberta Power and Saskatchewan Power would be amended to accommodate the larger interconnection and accepts that carrying charges would be paid by Saskatchewan Power up to the end of 1994, as described in the present agreement.

The Board also notes that the interveners at the hearing into the original application have advised that they do not object to Alberta Power's amended application.

The Board agrees that the incremental cost for the 150-MW interconnection is very attractive and is of the view that this would not conflict with other matters previously dealt with in its Decision D 87-14. Even though each system would depend on the interconnection for only 125 MW of reserve generating capacity beginning in 1995, the Board expects that other benefits, as stated in the original application, would still be valid for the 150-MW interconnection.

The Board, upon consideration of the additional information provided, finds that the 150-MW interconnection would be in the public interest.

The Board has reviewed the final route of the 230-kV transmission line and finds it to be satisfactory.

Therefore, the Board is prepared to approve the amendment to Alberta Power's application for the construction and operation of a 150-MW interconnection facility with Saskatchewan Power. It is also prepared to approve the 230-kV line route between the McNeill DC Converter Station and the Alberta-Saskatchewan border. These approvals are subject to all the conditions stated by the Board in its earlier Decision D 87-14.

DATED at Calgary, Alberta, on 20 November 1987.

ENERGY RESOURCES CONSERVATION BOARD

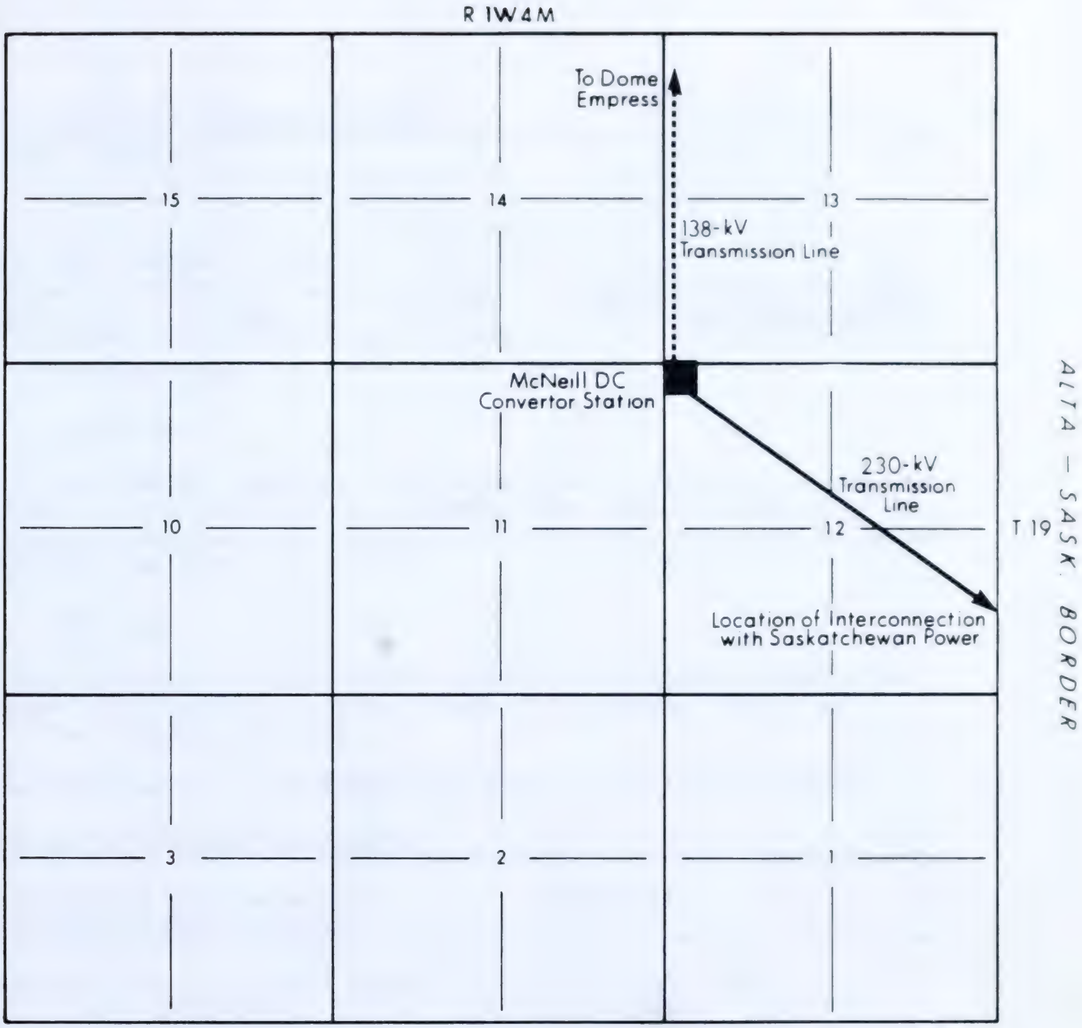
C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

J. Prince

J. P. Prince, Ph.D.
Board Member



LOCATION OF FACILITIES FOR THE PROPOSED
ALBERTA-SASKATCHEWAN DC INTERCONNECTION
Application No. 870308
Alberta Power Limited

Addendum
to D87-14
ERCB

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

PEACE PIPE LINE LTD.
PIPELINE CONSTRUCTION AT ROAD CROSSINGS
COUNTY OF LAC STE. ANNE

Decision D 87-15
Application 870791

1 INTRODUCTION

1.1 Application

Peace Pipe Line Ltd. applied, under section 41 of the Pipeline Act, for approval to construct a 508-millimetre outside diameter crude oil pipeline across four roads within the County of Lac Ste. Anne, as shown on the attached plan.

1.2 Hearing

A public hearing of the application was held in Edmonton, Alberta, on 11 August 1987, with F. J. Mink, P.Eng., J. P. Prince, Ph.D., and R. G. Evans, P.Eng., sitting.

Those who appeared at the hearing are shown in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Peace Pipe Line Ltd. (Peace Pipe) F. M. Saville Q.C.	J. A. Ion, P.Eng. L. A. Ledene
County of Lac Ste. Anne (County) M. C. Welsh	T. Nelson
Energy Resources Conservation Board staff A. Broughton J. S. Owen M. P. Vandenbeld	

1.3 Background

In February 1987, Peace Pipe applied to the Board for a permit to construct some 5 km of 508-mm O.D. pipeline to by-pass the town of Mayerthorpe; this would replace an existing crude oil pipeline within the town. The Board approved the construction through Permit No. 6986, issued on 13 March 1987.

Since the pipeline would cross three roads and one undeveloped road allowance, Peace Pipe requested County approval of these crossings during March 1987. This approval, required under section 40 of the Pipeline Act, could not be obtained by Peace Pipe except under conditions which Peace Pipe deemed unacceptable. Given that it could not reasonably obtain approval from the County, Peace Pipe therefore applied to the Board for final approval under section 41 of the Act.

Negotiations did continue between Peace Pipe and the County after the filing of the application, and on 15 May 1987 Board staff held a mediation meeting in an attempt to reconcile the differences and avoid a formal hearing.

This was unsuccessful and the application was set down for public hearing.

2 ISSUES

The Board considers the issues respecting the application to be the conditions requested by the County to be imposed to approve the construction:

- o the future costs of relocation,
- o the need for a security deposit,
- o locating, marking, and exposing the pipeline, and
- o the depth of cover.

The County attempted to negotiate a master agreement with Peace Pipe on all of these conditions in the hope that the agreement would be binding on all pipeline construction carried out by Peace Pipe within the county in the future.

3 EXAMINATION OF THE ISSUES

3.1 Future Costs of Relocation

Peace Pipe stated that the County's initial demand that Peace Pipe commit at this time to bear the entire expense of any future pipeline relocation caused by road alteration was unreasonable. Peace Pipe was prepared to install the road crossings at whatever depths and locations are required by the County, providing the County makes a reasonable assessment of future road requirements.

Peace Pipe noted that the costs of working on a major transmission pipeline could be considerable, and that proper initial installation could minimize the need for such expenditures in the future. It observed that even if some form of future cost sharing were agreed to as discussed during negotiation with the County, this could obligate the County to pay a large amount in the future as its share of a major relocation.

In Peace Pipe's opinion, the mechanism already exists through section 34 of the Pipeline Act for the Board to determine the need and allocation of costs for any future pipeline relocation, should Peace Pipe and the County be unable to reach agreement at that future date. Peace Pipe therefore requested that the Board grant the approval without conditions related to the sharing of future relocation costs.

The County stated that although its initial request was for Peace Pipe to bear the entire cost of any future relocation, it subsequently offered a cost-sharing agreement to Peace Pipe. Under this agreement, Peace Pipe would bear the cost of vertical relocation within the road right of way, and half of the cost of any horizontal relocation within the road right of way. The County would bear the entire cost of any pipline relocation outside the road right of way, where this was needed because of road alteration. The County had further offered to bear the entire cost should a second relocation be needed within 15 years of a previous relocation at the same road.

The County noted that several other pipeline companies had previously agreed to bear the entire cost of future relocations, although it acknowledged that none of the pipelines in question were major transmission lines.

The County agreed with Peace Pipe that, under the cost-sharing agreement favoured by it, there was some risk of major expenditures by the County in the future. However, it believed this risk was slight, provided it used its best efforts in reviewing future needs at each crossing location.

Views of the Board

The Board notes that the County has elected to enter into agreements with pipeline companies instead of simply issuing approvals as provided under section 40 of the Act. This practice appears to have been acceptable to several pipeline companies, according to the testimony of the County.

It is clear that Peace Pipe was also prepared to enter into such an agreement with the County, as evidenced by the lengthy negotiations.

It is the Board's opinion that the Act does not require such an agreement; however, it understands that a form of conditional approval has been contained in previous agreements.

The Board notes there is no disagreement between the County and Peace Pipe about the magnitude of costs which could be incurred in any future relocation of this major transmission line. The Board believes the County has made a sincere effort to anticipate future road needs, as evidenced by the County's request for an increased cover depth at one crossing. The Board agrees that this should minimize the risk of major expenditures in the future at this location, and notes that Peace Pipe is prepared to install the line at the increased depth.

The Board also notes that the County finds the location of the crossings to be acceptable from the standpoint of existing and future road requirements.

The Board confirms that a pipeline permittee is required to install road crossings to the minimum requirements of the Pipeline Regulation and the standards incorporated therein. The Board also believes it is prudent to increase these requirements where an engineering assessment demonstrates a need. In addition, where a local road authority has specific knowledge of matters which could affect the future integrity of the pipeline, or knowledge of a planned change to a road alignment or grade, this should be made known to the pipeline permittee and considered in the crossing design.

Although the chance of future pipeline relocation may be slight, the Board agrees that the cost of such works could be considerable. It believes that an expensive relocation in the future may be avoided or other solutions found by discussions between Peace Pipe and the County at that future date. It also notes that section 34 of the Pipeline Act would provide an opportunity for the need for such a relocation to be examined by the Board, and costs assigned, should discussions fail to reach a satisfactory solution. Given the provision in the Act to reconcile future disagreements, the Board does not believe it is appropriate to condition the permit on future relocation costs.

3.2 Need for a Security Deposit

The County stated that Peace Pipe would be required to place a security deposit of $10 000 with it as part of an agreement to allow the installation of the road crossing to proceed. This requirement has been standard throughout the County since 1985 and is required in order to ensure payment for repair of road damage caused by the depositor.

The County also referred to one incident of road damage which it maintains was caused by a contractor for Peace Pipe in 1985. It stated that it had difficulty at that time in having Peace Pipe acknowledge responsibility for the damage and make compensation for the cost of repairs. The contractor ultimately paid for repairs carried out by the County.

Peace Pipe questioned the need for such a deposit in its case. It acknowledges its responsibility for making good or providing payment for the repair of roads damaged during pipeline construction work, and stated that any delay in the past was caused by a failure on the part of the County to contact Peace Pipe directly, rather than Peace Pipe's contractor.

Views of the Board

The Board does not consider it appropriate to require the posting of a security deposit in this instance. Peace Pipe has an obligation to install its pipeline with minimal disturbance of the earth, and to reinstate the surface to as near original condition as possible; and recourse is available through this Board, the Surface Rights Board, or the Land Reclamation Council should Peace Pipe not meet this obligation.

The Board does consider, however, that Peace Pipe should ensure that the County is able to communicate easily with it without needing to discuss the matter with Peace Pipe's contractor.

3.3 Locating, Marking, and Exposing the Pipeline

Peace Pipe stated that it would, in accordance with the requirements of the Pipeline Regulation, provide surface location of its pipelines and of marking their positions when requested to do so by the County in the future. Furthermore, it would provide supervision during hand excavation around the pipeline by the County, as a matter of policy.

Peace Pipe stated that there was no hazard to personnel digging around the pipeline with hand tools, and that any damage to the coating was usually repaired by Peace Pipe without charge.

The County was concerned that its personnel could be endangered by excavating around the pipeline in the future. It stated that the Workers' Compensation Regulations prevented County personnel from excavating around pipelines without adequate training, and that it expected opposition from the Canadian Union of Public Employees if County personnel were required to do such work.

Views of the Board

The Board confirms that Peace Pipe is responsible for the surface location and marking of its pipelines and believes that Peace Pipe has the information and resources to do this. However, it believes that the County, if it decides to carry out a ground disturbance above the pipeline, can better identify the timing of hand exposure and can provide personnel with hand tools to carry out the work. Although the County can certainly request the attendance of a Peace Pipe representative, the Board notes that Peace Pipe's commitment goes beyond the legislation by providing supervision without request as a matter of policy. The Board notes that such an arrangement is in accordance with the Regulation.

In the Board's judgement, hand excavation around steel pipelines for the purpose of locating is not a hazardous operation. It recognises that certain safety procedures regarding working in any excavation must be followed, and expects that the County will provide the necessary training for its personnel to accomplish that task.

3.4 Depth of Cover

Peace Pipe stated that its proposed minimum depth of cover of 1.5 m below the road ditch level was greater than required by statute and provided an additional measure of protection against damage by heavy equipment. Peace Pipe was prepared to place its pipeline deeper where road layout or ground conditions made this necessary.

The County accepted that the standard cover depth was adequate for current road conditions. However, it stated that road reconstruction in the future could require such pipelines to be lowered.

The County believed that one of the proposed road crossings between the northeast and southeast quarters of section 30 could be upgraded in the future, and that a depth of 3 m would be appropriate to avoid future pipeline lowering.

Views of the Board

The Board notes the general agreement upon the 1.5-m depth of cover. It also considers the argument about future upgrading of one road to be persuasive and notes Peace Pipe's agreement with the 3-m depth of cover at that location.

Although the Board does not believe that routine burial to excessive cover depths is an economically justifiable solution to avoid future relocation, it considers that burial to a moderate depth is acceptable when the need for it can be supported.

4 DECISION

Given the evidence, the Board approves the construction of four pipeline road crossings within the County of Lac Ste. Anne, subject to Peace Pipe meeting the following condition:

- Peace Pipe to install the pipeline between the NE 1/4 of section 30 and the SE 1/4 of section 30, township 57, range 8, west of the 5th meridian, at a minimum depth of 3.0 m below the invert of the road ditches.

Dated at Calgary, Alberta, on 23 September 1987.

ENERGY RESOURCES CONSERVATION BOARD

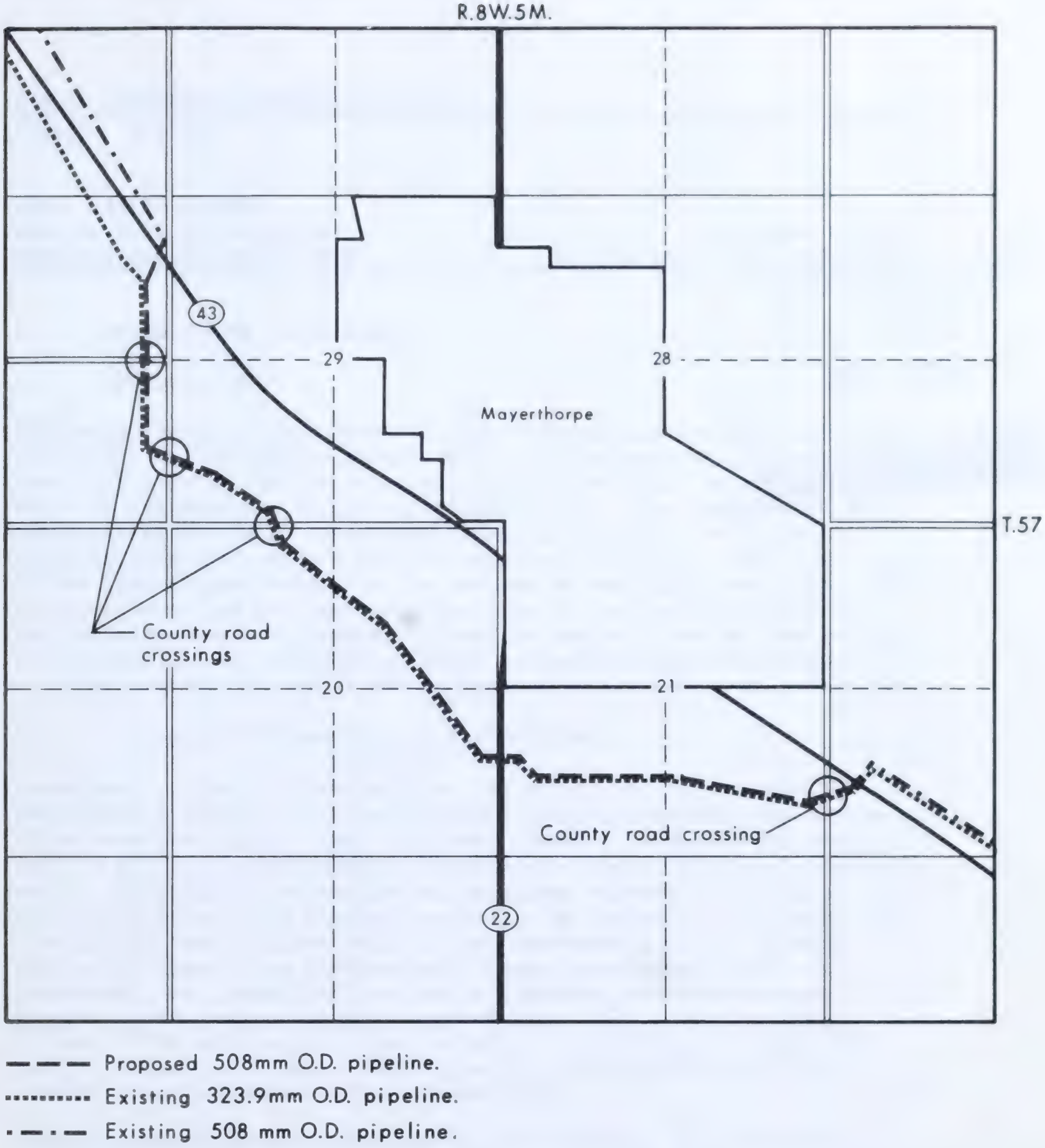
F. J. Mink, P.Eng.
Board Member

J.P. Prince

J. P. Prince, Ph.D.
Board Member

R G Evans

R. G. Evans, P.Eng.
Acting Board Member


R.8W.5M.
T.57
43
29
28
Mayerthorpe
County road crossings
20
21
County road crossing
22
Proposed 508mm O.D. pipeline.
Existing 323.9mm O.D. pipeline.
Existing 508 mm O.D. pipeline.

COUNTY ROAD CROSSINGS WITHIN COUNTY OF LAC STE. ANNE
Application No. 870791
Peace Pipe Line Ltd.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA LIMITED
WELL LICENCE APPLICATIONS
WATERTON/PRAIRIE BLUFF AREA

Decision D 87-16
Application 870417 and 870418

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1 APPLICATIONS AND HEARING

1.1 Applications

The Energy Resources Conservation Board (Board) received applications from Shell Canada Limited (Shell) dated 13 February 1987, pursuant to Part 6 of the Oil and Gas Conservation Act, for licences to drill two wells in the Waterton Field near Pincher Creek. The proposed wells, SHELL WATERTON 2-29-4-1 and SHELL WATERTON 12-29-4-1, would be directionally drilled from surface locations at 14-20-4-1W5M and 8-30-4-1W5M respectively, for the purpose of obtaining production from the Mount Head and Livingstone Formations of the Rundle Group within the Waterton Sheet IV structure (Waterton Rundle D Pool as designated by the Board). On the basis of expected productivity and hydrogen sulphide content, the wells are designated as critical sour gas wells.

1.2 18 August 1987 Hearing and Rescheduling

Subsequent to Shell's disclosure to the public of its proposed developments and prior to the filing of the applications, the Alberta Wilderness Association (AWA) expressed concerns to Shell, the Board, and the Alberta Forest Service regarding the location of the proposed wells. Considerable correspondence occurred between Shell and the AWA prior to submission of the applications. By letters to the Board dated 2 April 1987 and 16 June 1987, the AWA requested a public hearing of the applications if an Environmental Impact Assessment (EIA) was not conducted. As a result of continuing concerns over environmental issues, a hearing was convened on 18 August 1987 in Pincher Creek. Notice of the hearing was given verbally to the AWA on 30 June 1987 and in writing on 11 July 1987 but was not advertised in the local Pincher Creek newspaper until 4 August 1987.

Prior to presentation of evidence at this hearing, the Board heard requests from both the AWA and local area residents for postponement of the hearing on the basis of insufficient preparation time. The Board expressed the view that the AWA had been aware of the applications for a considerable period of time prior to actually receiving notice of the hearing and therefore had ample time to prepare. However, in recognition of the short notice given to the local residents, the Board closed the hearing and rescheduled a new hearing for 16 September 1987.

1.3 16 September 1987 Hearing

The hearing of these applications was held on 16 and 17 September 1987 before C. J. Goodman, P.Eng., F. J. Mink, P.Eng., and E. G. Fox, P.Eng. The participants at the hearing are shown in Table 1.

At the outset of the hearing the Pincher Creek Area Environmental Association (PCAEA) expressed concerns over health problems of some area residents which they attributed to sour gas activities in the area. It indicated that many of the witnesses it intended to call were unavailable on the hearing date. Although it did not ask the Board to adjourn the hearing, it did request the Board to reopen the hearing at a later date when more of its witnesses would be available to present evidence. It stated that only a small portion of its group would be available at the 16 September hearing. The Board deferred its decision on this matter until after the evidence of the available witnesses was heard.

After hearing the evidence, the Board ruled that sufficient notice had been given to the PCAEA to arrange to have its witnesses present. It further ruled that there had also been ample time for area residents to make a written submission to the hearing on behalf of all the PCAEA witnesses. Notwithstanding that opportunity, the Board urged the PCAEA to present those witnesses available at the time. The Board noted that the evidence presented on behalf of the PCAEA (as discussed in Section 6.4.2) was, as acknowledged by counsel for the PCAEA, representative of the majority of the evidence of the remaining witnesses. The Board believed it had sufficient evidence to deal with these concerns and therefore saw no need for reopening the hearing at a later date.

Subsequent to the close of the hearing on 17 September 1987, the Board received a letter from the AWA dated 22 September 1987 expressing concerns that the actual construction of the proposed access road would result in a much greater impact than that described at the hearing. The AWA also requested the Board view the routing of the proposed access road on foot. After considering this request and a response from Shell to this matter by way of letter to the Board dated 29 September 1987, the Board agreed to view the route of the proposed access road first hand. It notified all participants at the hearing of its intentions and offered them an opportunity to accompany the Board on the site visit and comment on the proposed road. The Board walked the route of the proposed road on 2 October 1987. Table 2 lists the participants in this location visit.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) D. O. Sabey, Q.C.	J. R. Tilbe, P.Eng. R. W. Symonds, P.Eng. D. J. Hemphill, P.Eng. L. E. Morgantini Dr. D. A. Mead J. D. Scott R. T. Staysko, P.Eng.
The Crown, in the right of the Province of Alberta (Crown) B. Stone L. Fitch D. Wig A. Evans	
Alberta Wilderness Association (AWA)	V. Pharis D. Pachal
J. Tweedie	J. Tweedie
Lethbridge Fish and Game Association (LFGA)	R. Stewart
Federation of Alberta Naturalists (FAN)	H. Gardner
Pincher Creek Area Environmental Association (PCAEA) W. G. Geddes	D. McGlynn S. Taylor J. Main B. Crook
R. Jack	R. Jack
R. Matheson	R. Matheson
* Pincher Creek Economic Development Board * Great Bear Foundation * E. and P. Moskaluk * E. A. and S. Judd * Pincher Creek and District Chamber of Commerce	
Energy Resources Conservation Board staff R. J. Cox, P.Eng. T. L. Byrnes, P.Eng. C.J.C. Page	

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* Denotes parties that filed submissions but were not present at the hearing.

TABLE 2 PARTICIPANTS IN THE 2 OCTOBER 1987 VIEWING OF THE PROPOSED ACCESS ROAD

Affiliation	Representatives
Energy Resources Conservation Board	C. J. Goodman F. J. Mink E. G. Fox
Shell Canada Limited	D. Lang J. D. Scott J. R. Tilbe
Alberta Wilderness Association	V. Pharis D. Pachal C. Hoare
Alberta Forestry, Lands and Wildlife	A. Evans D. Wig D. Lyons G. Stuart H. Wollice
Pincher Creek Area Environmental Association	P. Waagner
Federation of Alberta Naturalists	H. Gardner
Others	J. Tweedie S. Judd E. A. Judd

2 BACKGROUND

2.1 Prairie Bluff Area

The proposed surface locations are situated on the top of the Prairie Bluff complex, also known as Corner Mountain, located in southwestern Alberta approximately 25 kilometres southwest of the town of Pincher Creek and approximately 15 kilometres north of Waterton Lakes National Park. The wells would be located within the confines of the Waterton Field, which currently contains a total of 66 wells and the Shell Waterton Complex Processing Facility. The location of the proposed well sites and key geographical features in the surrounding area are shown in Figure 1.

The Prairie Bluff Complex is a part of the northernmost portion of the Front Range of the Rocky Mountains and forms part of the eastern periphery of a high alpine area. The wells would be located at an elevation of approximately 2100 metres and would be within the Prime Protection Zone (Zone 1) as designated by the Castle River Sub-Regional Integrated Resource Plan (Integrated Resource Plan).

2.2 Castle River Sub-Regional Integrated Resource Plan

In 1977 the Alberta Government approved a document entitled "A Policy for Resource Management of the Eastern Slopes" (Eastern Slopes Policy) to provide direction for integrated resource management and planning for the entire Eastern Slopes region. This policy was revised in 1984. The Integrated Resource Plan was approved by the Alberta Government in June of 1985.

The Integrated Resource Plan identifies specific geographic zones and the associated activities which may or may not occur within these zones. A designation of Zone 1, as is the case of the proposed surface locations, is intended to preserve environmentally-sensitive terrain and valuable aesthetic resources and for the maintenance of watershed and wildland recreation values. Under this designation, "step-out" drilling of oil and gas fields may be permitted to the point of recovering reserves in place. Under the Eastern Slopes Policy, mineral surface leases (MSLs) in Zone 1 may be approved where adequate environmental protection can be ensured. In this case, MSLs have been issued for the proposed well sites, and the alignment of the access road has been agreed to by Alberta Forestry, Lands and Wildlife. The leases contain a number of environmental conditions, including the condition that no activity is allowed on these lands between 1 December and 30 April because of wildlife management concerns. Pursuant to Alberta Energy and Natural Resources Information Letter 84-9 (re Standard Operational Condition No. 620), MSLs in Zone 1 are issued subject to the condition that well licences are obtained from the ERCB prior to commencement of any clearing or construction.

Further information regarding the Eastern Slopes Policy, the Integrated Resource Plan, and associated zoning can be found in the Alberta Government publications "A Policy for Resource Management of the Eastern Slopes, Revised 1984" and "Castle River Sub-Regional Integrated Resource Plan (1985)".

3 ISSUES

Having considered the evidence, the Board believes the issues are

- the need for the proposed wells,
- the proposed locations of the wells, including potential alternatives to the proposed surface locations,

- the potential environmental impacts, including those on wildlife, of the proposed development, and
- mitigative measures that may be undertaken to reduce any such impacts.

Because the proposed wells are designated as critical sour wells, the Board also considers the drilling and emergency response plans to be relevant.

The Board does not see the policy referred to in Section 2.2 as an issue in its consideration of these applications.

4 NEED FOR THE WELLS

4.1 Views of the Applicant

Shell stated that its Shell 46 Waterton well located north of Prairie Bluff at 6-31-4-1W5M was drilled and tested to confirm continuity of the Sheet IV reservoir and the existence of reserves sought by the proposed wells. Accordingly, the proposed wells represent infill developments which are permitted in Zone 1 areas under the Eastern Slopes Policy and the Integrated Resource Plan. Shell acknowledged that some drainage of the area sought by the proposed wells was indicated by the Shell 46 Waterton well encountering a Sheet IV reservoir pressure of approximately 18 000 kilopascals (kPa) as compared to an initial reservoir pressure of approximately 35 000 kPa. However, it contended that additional drainage points are required for optimum recovery of the resources. Based on Shell's experience in the south end of the pool, it indicated that these drainage points are required to maintain an efficient well spacing due to the poor continuity of reservoir development, structural complexities, and erratic fracture development of Sheet IV.

Shell indicated that the bottom-hole targets proposed were selected on the basis of minimizing water problems and penetrating high-quality reservoir while attempting to maintain efficient spacing between drainage points. It further indicated that shifting of the targets would move the locations towards less productive reservoir or too close to adjacent wells for effective drainage.

Shell conducted reservoir simulation studies that indicated the proposed wells would recover 1380 million cubic metres of raw gas by the year 2010, of which 470 million cubic metres would be incremental over depletion without the proposed wells. This estimate assumes that operation of the Waterton Gas Processing Complex would end in the year 2010, and further assumes that the north end of the reservoir is homogeneous in nature. Shell added that this estimate is conservative and that the existence of any geologic complexities, which have not been included in the current model, would result in incremental reserves exceeding 560 million cubic metres. Shell stated that this increase of 20 per cent over the modelled estimate is justified based on previous experiences with reservoir heterogeneities in this and other foothills pools. Shell added that these additional drainage points would aid in recovery by mitigating potential water production problems, which were not accounted for in the model.

Shell also indicated that the proposed Prairie Bluff wells are required to help maintain the throughput at its gas plant and offset the declining production dedicated to its existing contract. Production from these wells would temper the declining deliverability of the Waterton Field but would not be sufficient to extend the life of the Waterton Complex. Responding to questions of the AWA on the immediate need for the gas, Shell added that the wells are needed to maintain current operations and that delaying the drilling reduces the economics of producing these wells as the gas plant may not be operating at a later date to process the gas.

With respect to the potential for the Waterton Complex to operate beyond the year 2010, Shell conceded that the assumption of 2010 was an estimate, but expected that the actual date would be in that range. Additional reserves to be brought on from the north end of the Waterton area, referred to as the Sorge structure, are already included in the estimate of plant life and are not expected to impact the life of the plant due to their relatively small size.

4.2 Views of the Interveners

The AWA intervened as a public interest group with a long-standing interest in the South Castle area that includes Corner Mountain. Specifically, the wells fall inside the boundaries of the AWA-proposed "Wildland Recreation Area" as shown in Figure 1.

The AWA expressed concern over the need for the wells from a recovery point of view, considering the reservoir drainage indicated by the depleted pressure at the Shell 46 Waterton well. It questioned Shell's estimate of incremental reserves, suggesting that the gas may be recoverable without the proposed wells. The AWA also questioned the need to hurry the development, with respect to the effect of a 1-year delay to conduct an EIA.

The LFGA referenced the current surplus of gas in Alberta. It questioned the need for the wells since many existing gas wells are shut in which should be depleted prior to drilling of new wells.

Mr. Tweedie intervened as an area resident. He recognized the right of Shell to apply for well licences in this area, but was opposed to any drilling at the proposed locations. He was also concerned that the gas from the proposed wells would be export gas not for Alberta use, and questioned the benefits of the wells to the Alberta public.

Mr. Jack stated that he is a third-generation rancher in the area and owns and operates land directly downwind from the Shell Waterton Complex. He supported the applications on the basis that the petroleum industry provides the area with a diverse economy, and that Shell has conducted its past operations in the Waterton Field in an orderly and responsible fashion.

4.3 Views of the Board

The Board has considered the available reservoir information on the Shell 46 Waterton well, and agrees with Shell that the proposed wells would represent further development of the existing Sheet IV reservoir. In this respect, the wells would comply with the criteria for drilling in Prime Protection zones.

Regarding the estimated incremental reserves, the Board believes that some uncertainties exist respecting the gas plant life, geological complexities, and pressure data used to make this estimate. Although it may not agree precisely with Shell's estimate of incremental reserves of 560 million cubic metres, the Board is satisfied that the proposed wells would result in the recovery of significant incremental volumes of natural gas that would represent benefits to Alberta. Notwithstanding that the gas would be sold under an export contract, the Board notes that both the revenues and royalties generated by the production and sale of that gas would serve to benefit the broad Alberta public, and that the benefits of these incremental reserves are not limited to Shell.

Regarding the suggestion of some interveners that recovery of this gas could be delayed, the Board accepts the relationship between recovery from these wells and the limited economic life of the Waterton Processing Complex, and that continued operation of the plant may not be economic at the later stages of depletion of the proposed wells. It believes that delaying development of the reserves jeopardizes the potential for maximizing gas recovery and therefore believes that development of this gas at the earliest stage optimizes recovery and is in the public interest. The Board also believes that the risk of water production reducing gas recovery from the reservoir can be minimized by the timely drilling of additional drainage locations. Regarding concerns over the current gas surplus, the Board considers it unrealistic to delay all gas developments until existing reserves are depleted.

The Board accepts Shell's interpretation that the proposed bottom-hole locations are appropriate for the economic drainage of the reserves in the northern portion of the pool, and is satisfied that the proposed wells are necessary for the efficient and timely development of the reserves. The Board therefore agrees with Shell that there is a need for the proposed wells.

5 ALTERNATIVE SURFACE LOCATIONS

5.1 Views of Shell

Shell indicated that the surface locations were chosen on the basis of natural wellbore drift during the drilling operation with respect to the bottom-hole targets. The direction and extent of horizontal drift of the wellbore were approximated based on the average deviations from adjacent wells.

Shell investigated alternative surface locations for the wells, both on and off the Bluff. With respect to alternatives on the Bluff to reduce visual impacts, Shell contended that such alternatives were an unacceptable distance from the subsurface targets. With respect to alternatives off the Bluff, Shell stated that it had conducted an extensive search of all areas east of the Bluff for accessing the bottom-hole targets through directional drilling.* Specifically, it considered locations at 2-29-4-1W5M (2-29) and 6-29-4-1W5M (6-29) as alternatives to the 8-30 and 14-20 locations respectively.

Regarding the 2-29 alternative, Shell indicated that the directional drilling required from this location represented a difficult wellbore path and would add to the drilling risk through the potential for hole drag, stuck pipe, and high torque. This was based on the drilling experiences of Shell 19 Waterton and Shell 45A Waterton which were both drilled in this manner. Shell estimated this drilling to have a 75 per cent chance of success, and added that the chance of success referred only to safely completing the well and did not refer to the probability of reaching the bottom-hole target. With respect to the surface location, Shell stated that the 2-29 alternative was located on a scree slope that is geotechnically unstable and has potential for subsurface movements. It referred to a well located on a similar slope, Shell 6 Waterton, where subsurface movements resulted in the loss of the well.

Regarding the 6-29 alternative, Shell indicated that directionally drilling from this location would require drilling parallel to the strike direction rather than the preferred direction of normal to the strike. Shell stated that, based on past experience, this represented an extremely difficult wellbore path and was not technically feasible, having an optimistic chance of success of 50 per cent. It noted that the 6-29 alternative was located at the base of two avalanche chutes and represented a safety hazard for the well.

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* It should be noted that the wells as proposed are "directional" only insofar as the natural deviation of the wellbore is concerned, whereas the term "directional" as used in the remainder of this report refers to planned deviation other than that of natural formation drift.

Shell added that both surface locations represented restrictive topography. Shell concluded that, based on associated safety considerations and the directional drilling difficulties, neither surface alternative was feasible.

Regarding numerous alternative surface locations suggested by the AWA, Shell stated that these locations were highly risky and did not represent viable alternatives. Through its scouting process, Shell determined that acceptable surface locations to the east were an unacceptable horizontal distance from the bottom-hole targets. The alternative to drilling the proposed wells from the Bluff, Shell contended, would be the loss of the incremental reserves.

The location of the surface locations considered and proposed are summarized in Figure 2.

5.2 Views of the Interveners

The AWA, as guided by its reservoir engineering consultant, suggested a number of alternative surface locations from which the reserves may be recovered. It also suggested that the reserves could be recovered from other bottom-hole targets that might allow drilling from off the Bluff. These bottom-hole targets are shown in Figure 2. The AWA questioned Shell's contention that slopes in the area are too steep or unstable, concluding that it believes alternatives are still available.

5.3 Views of the Board

After consideration of all suitable locations identified, the Board accepts that the proposed targets are optimally located to encounter good quality reservoir, minimize potential water problems, and optimize well spacing. With respect to alternative surface locations for the proposed wells, the Board notes that Shell has considered the area east of the Bluff during its scouting process, and that only two potential alternatives were located. The Board found Shell's analysis of the 2-29 and 6-29 alternative sites to be extensive and thorough.

With respect to directional drilling difficulties from these locations, the Board acknowledges Shell's discussion on directional drilling difficulties and recognizes Shell's expertise in drilling deep foothills wells. The Board accepts that these locations are, in the case of 2-29, considerably riskier, and in the case of 6-29, not technically feasible from a directional drilling perspective. The Board also recognizes the evidence presented by Shell regarding potential surface instability at the alternative locations. The Board believes that safety must be a paramount consideration in the planning of any well. On the basis of both surface instability and directional drilling difficulties, the Board believes that the 2-29 and 6-29 are not appropriate alternatives.

The Board recognizes the suggestions of the AWA that locations other than those considered in detail by Shell exist that would allow drilling from off the Bluff. Having regard for the evidence on directional drilling difficulties and the limited sites available for locating wells off the Bluff and still accessing the bottom-hole targets, the Board agrees with Shell that these locations would add significant risk to the drilling operation. Also, the Board heard no evidence to suggest that surface locations are actually available to drill these alternatives.

Notwithstanding consideration of the potential impacts of these locations, the Board therefore believes that, should the drilling of these wells be approved, the two surface locations as proposed are appropriate.

6 POTENTIAL IMPACTS

MSLs for the proposed access road and well sites were issued by Alberta Forestry, Lands and Wildlife on 13 February 1987. As a condition of these leases, activities at upper elevations are not permitted between 1 December and 30 April because of wildlife management concerns. Shell indicated that, given the activity window from 1 May to 30 November, road and well site construction as well as simultaneous drilling of both wells could occur within one window, but that it may not be possible to test the wells until the following year. Shell believed that prompt resolution of the decision on these applications would allow for some road construction this fall which would allow for completion and testing of the wells in the 1988 window. Pipeline and facility design would occur over the following winter.

Shell stated that surface disturbances in conjunction with these applications would include the construction of a 20-metre right of way (ROW) access road approximately 4 kilometres long and the construction of two well sites approximately 85 metres by 120 metres in size. Both the access road and the well sites would require some controlled blasting. In accordance with ERCB equipment spacing regulations, the production lease could be reduced to approximately 75 metres by 110 metres and each site would contain a wellhead, two small buildings, and a 12-metre flare stack.

During the production phase of the wells, the leases would be visited up to three times per week thereby requiring year-round road maintenance. Flaring from each well for approximately 20 minutes would occur twice per year.

6.1 Construction and Reclamation

6.1.1 Views of Shell

Shell stated it was confident that it could reclaim the surfaces to close to the original contour with the exception of some steep portions of the access road which would be bench stepped. Having had extensive experience with foothills reclamation, Shell was further confident that native species would revegetate the sites. It indicated that the prescribed commercial species specific for the area would be introduced, but it would be prepared to experiment in co-operation with authorities. Commercial species would be replaced by the natural revegetation of native species over time. Shell suggested that reclamation could take up to 5 years.

Regarding concerns of the AWA over the impact of road construction on Bar Creek and a waterfall located on that creek, Shell stated that the road would cross the creek bed only once and would be in the upper reaches where a culvert would be used, such that the drainage of the watercourse and the waterfall would not be affected.

6.1.2 Views of the Interveners

The AWA stated that no assessment of the impacts has been conducted, and that it is the responsibility of the proponent to conduct such assessments. The AWA also expressed concerns that a vegetation assessment has not been done, and doubted that reclamation at these high elevations would be possible.

As discussed in Section 1.3, the AWA expressed concerns to the Board after the close of the hearing regarding the routing and construction of the proposed access road with respect to its effect on Bar Creek and a waterfall located on the creek. The AWA suggested that the creek and waterfall would be obliterated by the road construction.

6.1.3 Views of the Board

Having considered the evidence, the Board recognizes that some impact on the environment would be inevitable, particularly with respect to surface disturbance. However, the Board believes that with responsible actions and mitigative measures, the proposed wells and related construction activities can be performed without significant lasting environmental impacts. The Board notes Shell's experience in foothills reclamation and would support Shell's suggestion of experimenting on reclamation procedures at the well sites after reduction to a production lease. The Board is satisfied that reclamation would be attainable.

As a result of the 2 October site visit, the Board has had the opportunity to consider first hand the concerns of the AWA regarding the potential impact of the proposed access road on Bar Creek. The Board is of the view that the watercourse should not be significantly affected.

6.2 Wildlife

6.2.1 Views of Shell

Shell indicated that through public consultation and a preliminary environmental assessment, it recognizes the Prairie Bluff as sheep habitat during the months of November through April. The preliminary assessment was conducted to identify possible issues and concerns and make recommendations on potential impact and mitigation. A second study of the bighorn sheep was initiated in October 1986, with input to the design of the study coming from Alberta Fish and Wildlife, Alberta Fish and Game Association, AWA, Shell, and Luigi Morgantini, a recognized expert on bighorn sheep. The intent of the study was to learn more about the sheep and confirm the window of opportunity to conduct operations with minimum impact. It identified the Prairie Bluff Complex as an important winter/spring habitat for bighorn sheep.

At the hearing, Mr. Morgantini acknowledged that there would be some impacts on the sheep but indicated that they would be minimal if the access road did not act as a barrier to sheep movements. He stated that the major impacts on the sheep would be displacement from winter range or attraction to the leases because of salts and other minerals. With respect to the effect of displacement, Mr. Morgantini indicated that this depends on the availability of alternate winter range which is as yet unknown. He added that continued monitoring of the herd through the second phase of the study during the 1987-88 winter would enable mitigative measures to be identified if impacts were significant. He stated that sheep are adaptable and it has been his experience that impacts can be mitigated.

In response to questions, Mr. Morgantini stated that the worst case scenario would be one in which the road acts as a barrier in a winter of severe weather conditions. Impacts under this scenario could threaten individual animals but would be very unlikely to wipe out the herd. Shell added that construction of the access road this fall would allow for the sheep to become habituated to it and the effect would be reduced.

Although Shell acknowledged the presence of other wildlife in the area, it indicated that, based on review by Shell and Forestry, Lands and Wildlife staff, its opinion was that impacts on these species would be minimal with access closure.

6.2.2 Views of the Interveners

The AWA suggested that the proposal would have detrimental effects on wildlife and stated that Shell has provided no documentation that the proposed well sites and access road would have no detrimental effects on the grizzly bear, wolverine, and cougar population of the area. Specifically with respect to the sheep, the AWA stated that the area has long been recognized as some of the world's best bighorn sheep habitat, but noted that it does not have a thriving population. It claimed that the development would have negative impacts such that habitat development and enhancement would have to be undertaken to compensate for the impacts. It preferred to delay activity until it is known whether or not these enhancement sites exist. The AWA stated that without a conscious effort to protect both population and habitat, the Rocky Mountain bighorn sheep could become an "endangered" species as compared with its current status of "vulnerable".

The LFGA stated that it believes the disruption associated with development activities should not be permitted in Prime Protection areas. It acknowledged Corner Mountain as a sheep wintering range and added that suitable winter range is already severely limited and further intrusion on Corner Mountain was unacceptable. A viable sheep herd, it concluded, will be more intrinsically valuable in the future than an exhausted gas well.

The FAN indicated that it is not opposed to development in general but wished to contribute to ecologically safe and responsible behaviour in the development of this project. However, it opposed development and industrial activities in the Prime Protection zones. It expressed concerns over access and access control, and over the possible attraction of sheep to the well sites because of mineral accumulations. The FAN stated that the necessary work should be possible without drastic long-term negative impacts if both Shell and the regulatory authorities have the will to ensure this. It added that monitoring should be extended to all plants, birds, and animals encountered.

Mr. Tweedie expressed concern over the future of the bighorn sheep and suggested that the Board must assess the relative value of the uncertain future of 40 to 50 sheep and their habitat compared to extraction of the incremental gas, and indicated that an EIA should be performed. He also questioned the need for the construction of a new access road when an existing trail was available, suggesting that it would be more reasonable to use existing access despite the visual impacts rather than a new access and disturbance that would be hidden from view but would penetrate the heart of good sheep country. Mr. Tweedie summarized that consideration of the evidence must balance all resources for the people of Alberta. He added that the benefits of short-term economic gain must be compared with the risks.

Mr. Matheson intervened as a local resident. He was concerned that industrial activity, including both drilling and road construction, may have a profound and possibly adverse effect on the wildlife population of the area. Specifically with respect to the sheep, he identified the area as critical winter range and further stressed the importance of this range for reproductive activities. Mr. Matheson contended that inadequate information exists pertaining to the effects of habitat disruption as well as stress created by human industrial activity.

6.2.3 Views of the Board

The Board notes that Shell has obtained the necessary mineral surface leases for construction of the access road and well sites through consultation with Alberta Forestry, Lands and Wildlife. It further notes that a condition of the surface leases is that activities at the higher elevations are restricted to a 1 May to 30 November window to avoid undue impacts on wildlife. The Board believes that Shell's efforts to date have considered the major potential impacts on the bighorn sheep, and supports Shell's intentions to monitor sheep during construction and drilling. Although the Board recognizes that the magnitude of the impacts on the sheep cannot be clearly defined, it accepts the expert evidence of Mr. Morgantini that impacts should be minimal. The Board believes the continued monitoring of the sheep, as proposed by Shell, is necessary to determine the impacts and expects the company to introduce mitigative measures as may be necessary.

The Board recognizes further efforts of Shell to address potential impacts on other wildlife through consultation with Alberta Forestry, Lands and Wildlife. It is satisfied that with effective access closure, impacts on these other species will be minimal.

6.3 Aesthetic

6.3.1 Views of Shell

With respect to concerns over impacts on the aesthetics of the area, Shell stated that visual impacts would be limited to aerial or higher elevation surveillance, depending on height and line of sight. Shell stated that access to the well sites was thoroughly investigated by Shell, Alberta Forestry, Lands and Wildlife, and Shell's consultant geotechnical engineer prior to selection of the proposed route. Other potential routes were rejected because of steepness of terrain or major visual impact. The proposed route would be visible only from the air or from higher westerly elevations.

During drilling, the rig mast may be visible from some vantage points but would not be visible from the towns of Pincher Creek or Waterton. Shell added that the placement of the production facilities on the low side of the well site will ensure that they are not visible from east of the Front Range.

Regarding concerns of the AWA respecting expertise in assessing the aesthetic impact, Shell indicated that it had its own in-house expertise and added that these impacts were considered and accepted by the Department of Forestry, Lands and Wildlife prior to approving the MSLs. Shell added that the area is currently subject to recreational activities such as travel by all-terrain vehicles and motorcycles.

Regarding the suggestion of burial of the powerline to reduce aesthetic impacts, Shell stated that this would require a wider ROW to maintain a safe distance between the powerline and the pipeline. This solution was therefore not practical.

6.3.2 Views of the Interveners

The AWA argued that the proposed developments would degrade the recreational potential for use by the public, and was concerned that Shell had not consulted a landscape architect for assessment of both aesthetic impacts and mitigation. It added that the proposed development would jeopardize the chances of the Waterton-South Castle ecosystem being designated as a World Heritage Site, and also jeopardize the integrity of the Waterton Biosphere Reserve and various other international programs.

Mr. Matheson added that the proposed wells and access road, followed by the installation of permanent production equipment, would degrade the aesthetic and recreational value of the area. He requested that the Board consider both the short- and long-term effects and reject the applications.

6.3.3 Views of the Board

The Board recognizes the aesthetic quality of the Prairie Bluff Complex but notes it has been used by the public for a variety of recreational activities, which appears to have included use by motorcycles and all-terrain vehicles. The Board questions that it is still a true wilderness area. While there would be some visual impacts because of the presence of an access road and well sites, the Board notes that such impacts would be limited to aircraft or higher elevation surveillance. Although visual impacts will be more extensive during drilling or flaring, such impacts are relatively short in duration. The Board believes the visual impacts from the operations, although objectionable to some, would be neither wide-ranging nor extensive.

Specifically regarding the proposed access road, the Board accepts the argument that alternatives to the proposed routing should be rejected on the basis of aesthetics, unacceptable steep terrain, and providing permanent access to the area. The Board notes that the route was selected in consultation with Alberta Forestry, Lands and Wildlife staff. After considering the evidence obtained through both the hearing and the location visit, the Board recognizes the impact but is satisfied that the proposed access route is the most appropriate choice from an aesthetic perspective.

The Board also recognizes the broad concerns of the AWA regarding various national and international programs such as the Waterton Biosphere Reserve and the nomination of the Waterton-Glacier Complex as a World Heritage Site. However, it notes the existence of numerous sour gas wells already much closer to the subject areas and believes that the proposed developments would have no detrimental impact on these or similar programs.

6.4 Sour Gas Production

6.4.1 Views of Shell

In response to questions regarding plant operations, Shell indicated that the overall production at the plant has been declining and will continue to decline despite the addition of future wells. Shell stated that the plant is licensed for SO_2 emissions of 81.9 long tonnes per day, but that present emissions rates are approximately 12 long tonnes per day. Despite the fact that Sheet IV wells represent the highest H_2S concentrations in the field, Shell argued that because of the declining field capability the amount of SO_2 emitted to the atmosphere would continue to decline.

6.4.2 Views of the Interveners

The PCAEA questioned Shell on the operations of the plant complex with respect to sour gas inlet/throughput and emission levels of SO_2, and expressed concerns over emissions from the Waterton Complex as well as sour gas operations in general. It presented local residents as witnesses who related health problems they believed to be attributed to sour gas operations. The reported health problems included headaches, nosebleeds, nausea, diarrhea, sinus problems, rashes, and eye and respiratory irritation. The witnesses also related incidences of livestock mortality and birthing defects. They suggested that the emissions and associated problems were at their worst during well testing. The PCAEA also expressed concerns over general environmental problems including potential groundwater contamination from Shell's off-lease sump.

With respect to pollution in the area, Mr. Jack indicated that emissions from the plant are basically of the nuisance variety and that the general environmental situation has improved over the last 15 years. He concluded that the proposed drilling should be allowed to proceed.

6.4.3 Views of the Board

With respect to the associated impacts of increased production to the Waterton Complex, the Board notes that plant capacity exists for the proposed wells under the present operating licence and that maintaining or supplementing deliverability through infill development is an established and logical practice. With respect to the impact of plant throughput, the Board notes that plant input is declining and will continue to decline despite production from the proposed wells.

Regarding the concerns of the PCAEA with respect to SO_2 emissions, the Board notes that the current SO_2 emissions are substantially below the licensed rate and that emissions are declining. It also recognizes that while the additional production from the proposed wells will result in a short-term increase in H_2S input and subsequent SO_2 emissions, such an increase will not be significant and will be well below previous levels. Indeed, the SO_2 emissions will continue to decline despite the addition of these wells. It therefore believes that production from the proposed wells would represent essentially no new impact on SO_2 emissions. The Board believes that the primary impacts to be considered pertain to the wells and their locations rather than the plant operations.

6.5 Drilling and Emergency Response Plans

6.5.1 Views of Shell

Pursuant to the requirements of an application for a critical sour well, Shell also submitted information on its drilling plan and emergency response plan. Shell indicated that the risk of a well control problem at this stage of development of the reservoir was extremely low. It added that no well control problems were experienced in the drilling of previous Sheet IV wells. Regarding discussions of two previous well control problems of Waterton wells, Shell contended that these were Sheet III wells and were not comparable situations.

With respect to the emergency response plan, Shell indicated only one temporary residence within the emergency planning zone.

6.5.2 Views of the Interveners

The PCAEA questioned Shell's emergency response planning with respect to evacuation of transients and hikers, and identified a second seasonally occupied building within Shell's emergency planning zone that was not included in the emergency response plan. It also expressed concerns over the potential for sour gas emissions from well control problems.

Mr. Tweedie questioned both the potential for and consequences of a loss of control and subsequent sour gas emissions, particularly in this harsh drilling environment. He indicated that despite Shell's drilling and emergency response plans, he remained skeptical of the technical reassurances of drilling safety.

6.5.3 Views of the Board

The Board has reviewed Shell's drilling and emergency response plans and finds them to be satisfactory for drilling these critical sour wells. However, the Board notes the evidence of the PCAEA regarding the existence of a second trapper's cabin within the emergency planning zone. If drilling is approved, the Board would require Shell to confirm the location of this cabin and include it in the emergency response plan.

7 MITIGATION OF IMPACTS

7.1 Views of Shell

Shell stated that surface disturbances would be minimized by incorporating the pipeline ROW into the access road ROW. Soils disturbed during construction would be stockpiled and reused at the time of initial reclamation. Upon completion of the drilling operation, the portion of the lease not used for the production facilities would be immediately reclaimed to experiment and provide experience for the most effective reclamation at the time of abandonment. Shell added that the sizes of well sites and production leases would be kept to a minimum.

Although Shell did not expect a significant impact on the sheep herd from its operation, it stated that continued monitoring of the animals would allow for impacts to be identified and appropriate mitigative measures to be implemented. Specifically, it stated that its plans for continued monitoring of the sheep movements and habitat during the 1987/88 winter would identify the regional significance of the Prairie Bluff Complex by identifying alternate winter ranges. The need and potential for habitat enhancement would also be identified through this phase of the study.

With respect to wildlife in general, Shell submitted that impacts would be minimized if access was controlled. In that regard Shell stated that vehicular access would be restricted by a sign identifying the road closure and the authority under which it was closed. The closure itself would be by a locked steel gate which would be manned by Shell staff during drilling and completion operations to restrict access to essential personnel. Shell stated that the gate would be strategically located at the start of a major rock face such that it could not be by-passed. Access control would continue throughout the productive life of the wells by means of the locked gate, after which restoration would permanently restrict access.

Shell indicated that the production facilities buildings would be earthtone to reduce visual impacts and that these facilities would only be visible from higher elevations. The flare stack could also be earthtone, or alternatively could be hinged to lie flat until needed. Access by the public, because of the proposed road closure, would be equal to or less than current levels.

Shell committed to other mitigative measures to reduce environmental impacts, including removal of all fluid wastes during the drilling and production phases to a remote disposal location, drilling a water well to avoid the need for water hauling if successful, and fencing the downwind edge of the lease to contain windblown refuse. Shell added that there would be no camp located on the Bluff, and that Shell policy prohibits pets, the use of firearms, and recreational vehicles.

Although Shell was confident that drilling of both wells could be completed within one activity window it added that, in the unlikely event that it could not, the well or wells would have to be left in a safe and suspended manner over the winter and drilling resumed the following year. Shell added that it would make any information with respect to drilling progress and the activity window available to the Board and government departments if requested. This also would apply to environmental aspects of the operation.

7.2 Views of the Board

With respect to mitigating the effects of surface disturbances, the Board believes that minimizing the extent of surface disturbances, conserving topsoil, and experimenting with revegetation methods at an early stage are responsible practices that would minimize surface impacts.

Regarding wildlife, the Board accepts Shell's undertaking to continue monitoring the bighorn sheep and to identify potential impacts and mitigative measures. It suggests that this could be extended to wildlife in general, and also believes vegetation should be considered. If the applications are approved, monitoring should be conducted in conjunction with Alberta Forestry, Lands and Wildlife staff who are knowledgeable about and responsible for such matters in the area.

The Board supports Shell's proposed plans for earthtone buildings and a hinged flare stack to minimize visual impacts. With respect to burial of the powerlines, the Board accepts that increasing the ROW to facilitate this operation would be a greater impact than the presence of the powerline above ground. The Board also believes that later salvage and reclamation would be simpler with an overhead line.

The Board agrees with Shell's intentions to restrict firearms, recreational vehicles, and pets at the well site, to remove all drilling and production fluid wastes to a remote disposal site, and other general mitigative measures. The Board believes that these are responsible, appropriate practices that would go a long way towards minimizing the potential for environmental impacts. However, the Board shares the concerns of the AWA and other interveners regarding access and access control, and believes that this represents a significant potential for impact if general vehicle access is permitted. The Board notes, however, that the mineral surface leases for the proposed wells require that access must be controlled by a locked gate. The Board notes Shell's intention to man the gate during drilling and completion, and would expect Shell to secure the gate such that it could not be by-passed during operation of the wells.

The Board notes that the activity window as stipulated in the MSLs would allow for drilling and completion of the well in one window but might not provide for contingencies in the event of delays in the drilling program. The Board also notes, and agrees with, Shell's commitment to leave the wells in a safe state if drilling cannot be completed within the window. Recognizing the importance of this window to wildlife management, if the applications are approved, the Board would require that Shell regularly update both the ERCB and Alberta Forestry, Lands and Wildlife staff on the progress of the wells with respect to the activity window in order to facilitate the termination of activities in a safe and environmentally acceptable manner.

5 DECISION

Having regard for the evidence presented at the hearing, the Board concludes that there is a need for the wells and that no practical alternatives can be identified for the proposed surface locations.

Further, the Board believes this development can proceed without significant long-term impact provided the commitments of the already-issued MSLs and those proposed by Shell are met. Close surveillance of potential impacts, particularly on the sheep, will be required by Shell in consultation with Alberta Forestry, Lands and Wildlife.

The Board is therefore prepared to issue the necessary licences for the proposed wells subject to the following conditions:

- Shell update Alberta Environment, Alberta Forestry, Lands and Wildlife, and ERCB staff at various stages during the drilling, construction, and testing operations with respect to environmental impacts, mitigation, and effectiveness of access control;

- Shell similarly update ERCB and Alberta Forestry, Lands and Wildlife staff on the progress of drilling operations with respect to the potential for not completing operations within the prescribed activity window;

- Shell continue liaison and discussion of its mitigative measures with public interest groups; and

- Shell confirm the location of the second seasonally occupied building within its emergency planning zone and incorporate this building into its emergency response plan.

DATED at Calgary, Alberta, on 26 October 1987.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman
Board Member

F. J. Mink
Board Member

E. G. Fox

E. G. Fox
Acting Board Member

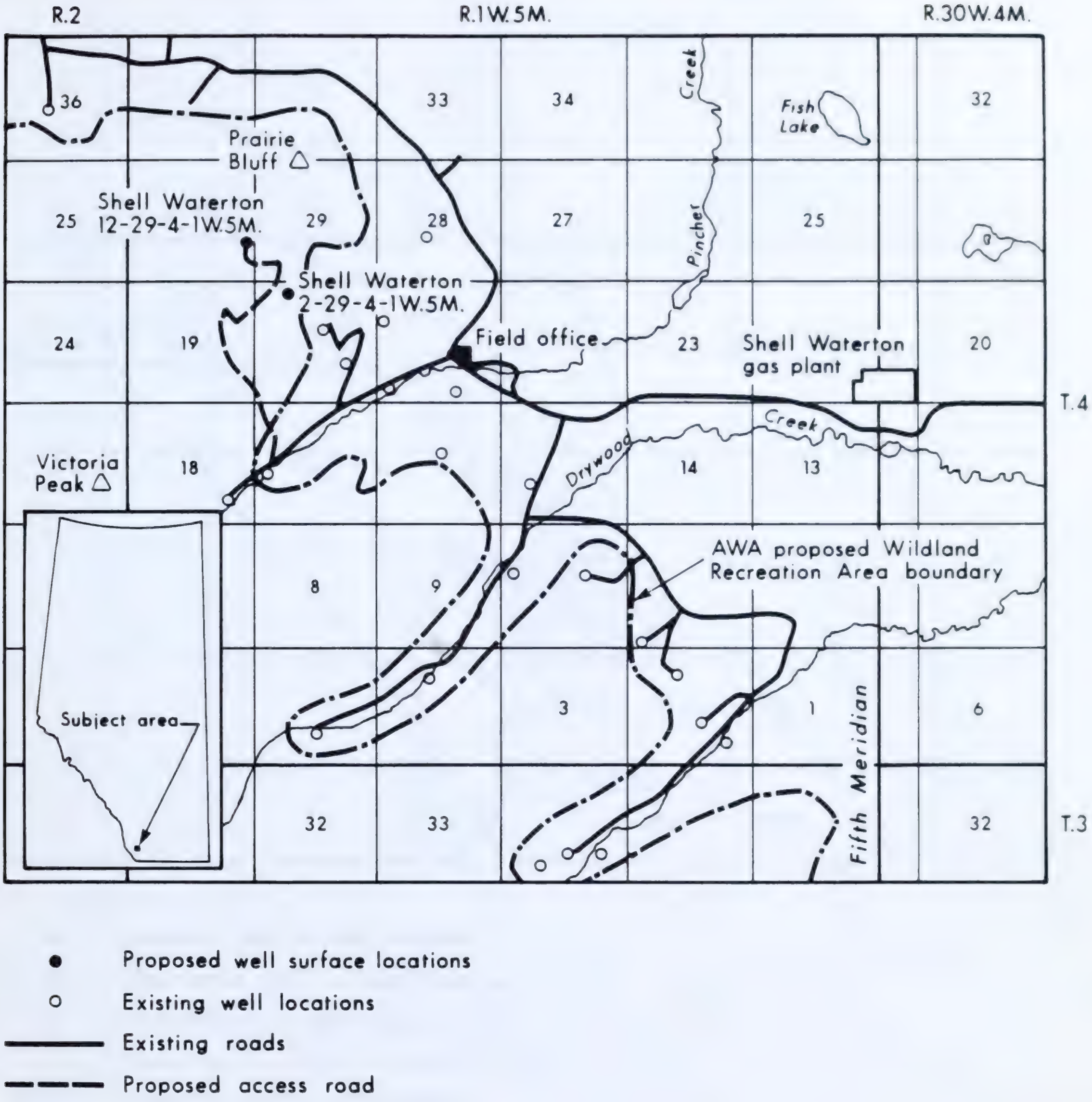

FIGURE 1 LOCATIONS OF THE PROPOSED PRAIRIE BLUFF WELLS
Applications No. 870417 & 870418
Shell Canada Limited

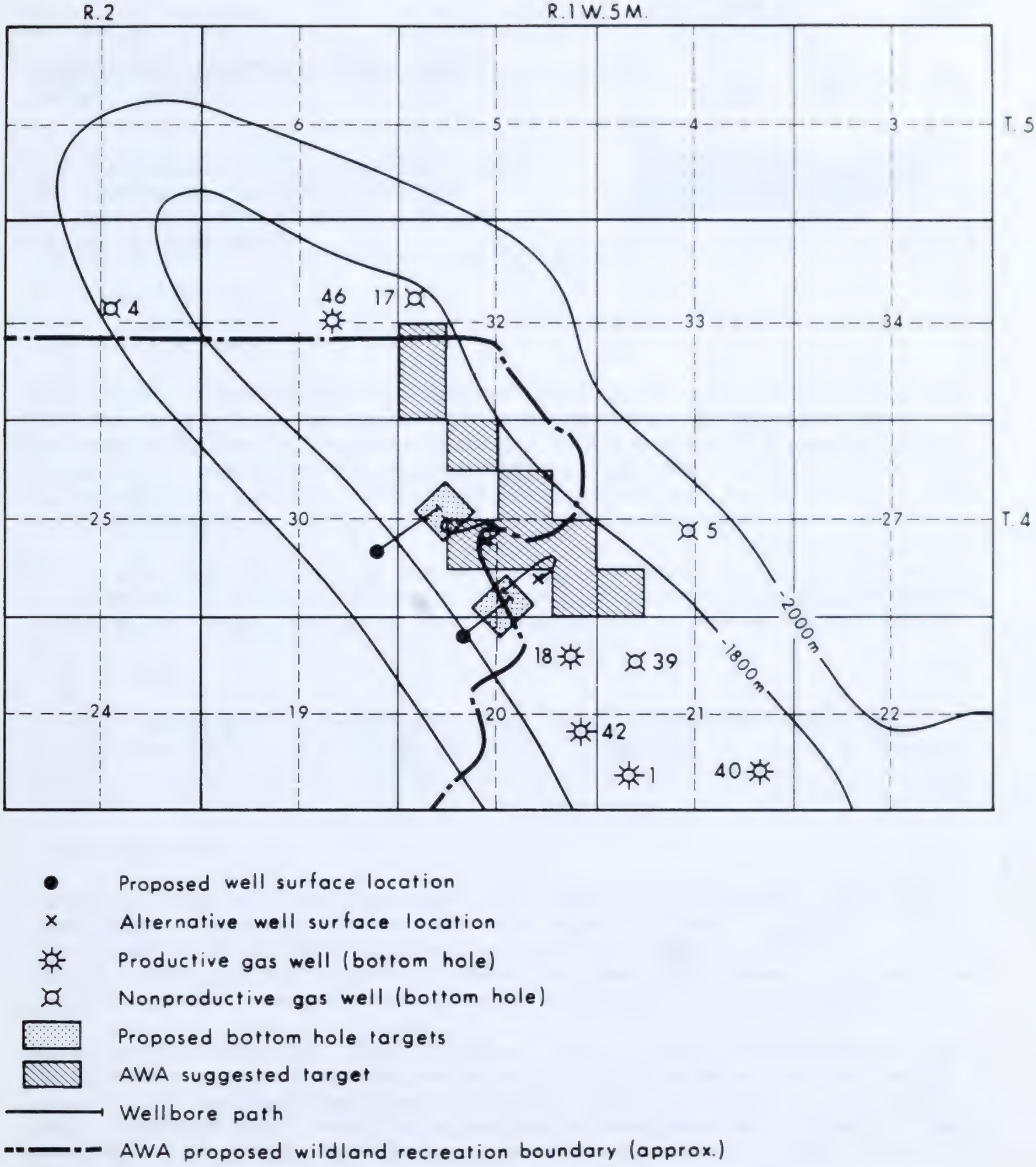
R.2
R.1 W.5 M.
T.5
T.4
6
5
4
3
4
46
17
32
33
34
25
30
27
5
18
39
2000 m
1800 m
24
19
20
21
22
42
1
40
● Proposed well surface location
× Alternative well surface location
☼ Productive gas well (bottom hole)
¤ Nonproductive gas well (bottom hole)
Proposed bottom hole targets
▨ AWA suggested target
Wellbore path
AWA proposed wildland recreation boundary (approx.)

FIGURE 2 ALTERNATIVE BOTTOM HOLE AND SURFACE LOCATIONS
Applications No. 870417 & 870418
Shell Canada Limited

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY GULF CANADA CORPORATION FOR PERMITS TO CONSTRUCT PIPELINES TO TRANSPORT SOUR GAS AND FUEL GAS IN THE CAROLINE AREA

Decision D 87-17
Applications 871017 and 871018

1 INTRODUCTION

1.1 Applications

Gulf Canada Corporation (Gulf) applied, pursuant to Part 4 of the Pipeline Act, for a permit to construct 15.9 km of 168.3-mm O.D. pipeline and related facilities to transport sour gas with a maximum H_2S content of 450 moles per kilomole from an existing well in legal subdivision 8 of section 1, township 36, range 6, west of the 5th Meridian (8-1 well), to an existing compressor station in Lsd 3-36-35-5 W5M (Figure 1).

To provide sweet fuel gas to the well site, Gulf also applied for a permit to construct 13.5 km of 88.9-mm O.D. pipeline to transport fuel gas from an existing Gulf pipeline tie-in point at Lsd 8-34-35-5 W5M to the 8-1 well.

1.2 Hearing

A public hearing of the applications was held in Caroline commencing 15 September 1987 with N. A. Strom, P.Eng. (Chairman), H. Antonio, P.Eng., and R. G. Evans, P.Eng., sitting. Participants at the hearing are listed in Table 1.

1.3 Background

Gulf filed copies of correspondence from Shell Canada Limited and others submitted to the Board in June 1987 that urged the Board to defer consideration of the Gulf applications until such time as a fully co-ordinated plan for field development had been established by the various working interest owners in the major Caroline Swan Hills sour gas pool.

In response to the Shell Canada Limited (Shell) letter, Gulf informed the Board of its reasons for disagreeing with Shell's proposal and went on to request that the Board set the applications down for hearing. As a result, while the hearing was technically devoted to consideration of the pipeline and related facilities applications, the focus was clearly given over to the major question of whether or not tie-in of the 8-1 well and commencement of production at this time via a pipeline system connecting it to the Strachan gas plant would trigger development activities in the Caroline Swan Hills Pool that would be disorderly and pose adverse environmental impacts. In anticipation of this question, Gulf seated a panel to address the broader issues of economic, orderly, and efficient field development.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Gulf Canada Corporation (Gulf) D. G. Hart, Q.C. D. Gandar	C. Mothersele T. R. Lennox, P.Geol. J. Caffrey, P.Eng. J. P. Cooke L. Callow
Shell Canada Limited (Shell) D. O. Sabey, Q.C.	H. Lyon, P.Eng. W. Welling, P.Eng
Union Pacific Resources Inc. (Union Pacific) J. F. Curran	L. Mendioro E. Kalthoff
Canterra Energy Ltd. (Canterra) F. M. Saville, Q.C.	
Dome Petroleum Limited (Dome) D. A. Holgate	
DeKalb Petroleum Corporation R. Smith	
W. Hall	W. Hall
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff N. C. Harris, P.Eng. H. R. Keushnig, P.Eng. L. Whittaker A. A. Broughton	

Canterra and Dome participated in the hearing for the purposes of cross-examination and argument only, and did not present any direct evidence.

Mr. Hall filed a submission but participated in the hearing for the purposes of cross-examination only.

DeKalb Petroleum Corporation was present at the hearing but did not participate.

Dr. M. Kostuch filed a submission but was not present at the hearing.

This report therefore deals with the specifics of the applications before the Board, but in addition, addresses other matters including statutory matters which should be taken into account when dealing with such an application and the substance of the general positions put forward both by the applicant and those opposing the application on grounds other than the particulars of the pipeline and related facilities applications.

2 POSITION OF PARTICIPANTS

2.1 Gulf

Gulf provided a general overview of its activity in the general Caroline-Strachan Area, making reference to a number of sour gas wells that it has drilled in recent years as a means of sustaining the supply to its modernized Strachan gas plant. It pointed out that the pipeline facilities would be designed to transport 700 x 10^3 m^3/d (25 million scfd) of Swan Hills sour gas to the Lanaway booster station. Though the 8-1 well ostensibly could produce near that limit, the intent was to produce it initially at a rate of approximately 140 x 10^3 m^3/d (5 million scfd), because of some restrictions of the level 2 operating licence for the Garrington-Lanaway pipeline system. No modifications would be required to the Garrington-Lanaway pipeline or the Strachan plant to handle the initial rates.

Gulf compared the Caroline Swan Hills Pool to the Snipe Lake Beaverhill Lake oil pool in northern Alberta, and by analogy anticipated the possibility of geological discontinuities and subpools within the Caroline reef. Also, it cited differences between the gas compositional analyses of the 8-1 well and other Caroline wells as indications that the 8-1 well might be in a separate reservoir.

With an important stake in the Caroline Swan Hills Pool, Gulf indicated its support for the concept of orderly development and advised that it was actively discussing options for larger scale development with Shell and other industry members. In fact, it viewed the tie-in of the 8-1 well as an important early step in the orderly development of the pool. Its view was that stepwise development would lead from the initial small rate at the 8-1 well to an intermediate level of 1400 x 10^3 m^3/d (50 million scfd) and finally to an ultimate level of 5600 to 8400 x 10^3 m^3/d (200 to 300 million scfd) in 4 or 5 years. Production performance from the 8-1 well would provide key information respecting reservoir drainage and fluid composition, optimum design of well site gathering and processing facilities, and enhancement of the economic, environmental, and safety aspects that must be addressed for large-scale development. Gulf contended that production information from the 8-1 well would thereby assist in expediting unitization negotiations and facilitate long-term exploration and development plans in the area.

In response to Shell's letter of intervention, Gulf pointed out that the pipeline corridor from the 8-1 well to the Lanaway booster station had received only one objection from an affected landowner. Gulf indicated that this corridor may provide a route for pipelines connecting other wells in future. It pointed out that its application involved no further incremental environmental impacts since the gas production would be moved from Lanaway to Strachan via an existing pipeline system and the processing would occur within the existing Strachan gas plant.

Respecting the prospects of drainage of reserves of other potential owners in the Caroline Swan Hills Pool, Gulf illustrated by its calculations that 5 years of production at the proposed 140 x 10^3 m^3/d rate would result in depletion of only 10 per cent of the estimated reserves in section 8 or 0.35 per cent of the total 56 000 x 10^6 m^3 (2 trillion scf) of reserves estimated to exist within the pool.

2.2 Shell

From the six wells it had tested, Shell found that the fluids that could be recovered were primarily gas, gas liquids (ethane, propane, butane, and hydrocarbon condensate) and sulphur in the form of H_2S. Shell described the pool as an unusual gas-liquids-sulphur reserve with in-place raw gas reserves of some 56 000 x 10^6 m^3.

Shell believed that to establish a plan for the gathering and processing of some 5600 x 10^3 m^3/d (200 million scfd) of these sour hydrocarbon fluids from a 25-km-long, narrow pool in a relatively populated area would require a special public involvement program. It suggested that the tie-in of the 8-1 well at this time would pre-empt such a program and might trigger drilling and production actions by individual operators that could create complications in obtaining consensus among landowners respecting an overall field development plan.

Shell, therefore, took the position that the central issue was not demonstration of well productivity or reservoir fluid composition but instead was the larger question of orderly, safe, and efficient development of the Caroline Field. It stated that formulation of an overall development plan which would facilitate public input, including consideration of development options, was important to avoid unnecessary impacts and future impediments to efficient development. It believed that allowing production from the 8-1 well to commence now could lead to increased drilling and duplication of facilities, and could tip the scale toward disorderly and inefficient development. Shell also stated that it believed that a lengthy production test of the 8-1 well, as proposed by Gulf, would in actuality provide little more information than that already available from the short production tests that have been conducted.

2.3 Union Pacific

Union Pacific supported Shell's position regarding the 8-1 well, and also stated that offset drilling obligations would be triggered and drainage would occur as a result of the well being put on production. It voiced the opinion that the application should be deferred for a reasonable period of time to allow the working interest owners involved to develop an overall strategy for the pool. Although it recognized that Gulf's applications for the facilities per se were in the narrower sense straightforward, it contended that a broader perspective, including the impact of the total pool development on the individuals and the community in the Caroline area, should be borne in mind in reaching a decision concerning those applications.

2.4 Canterra

Canterra took a neutral position respecting the application, but endorsed the concept of early assessment of exploitation options including consideration of process plant possibilities.

2.5 Dome

Dome did not oppose or support Gulf's application. It was, however, of the opinion that any approval issued at this time should not be such as to preclude alternatives for development, gathering, and processing of production from the pool.

3 RELEVANT LEGISLATION

Union Pacific submitted that, in considering the subject applications, the Board has a legislative duty to safeguard the public interest and to have regard for the economic, orderly, and efficient development of the Caroline reserves and the pipeline and other facilities required to transport those reserves. It argued that this legislative duty arises under section 5 of the Pipeline Act and section 4 of the Oil and Gas Conservation Act.

Gulf submitted that there was no express provision in the Pipeline Act or the Regulations imposing an onus or a burden on an applicant for a pipeline permit to establish that the proposed pipeline represented economic, orderly, and efficient development in the public interest. While Gulf acknowledged that section 5 in Part 3 of the Pipeline Act empowered the Board (on its own motion or at the direction of the Lieutenant Governor in Council) to investigate matters relating to the economic, orderly, and efficient development in the public interest of pipeline facilities in Alberta, it submitted that this was an investigative power under Part 3 of the Pipeline Act, and that the subject applications were being considered under Part 4 of the Pipeline Act where no such provision appears. It argued that this onus, proposed by Union Pacific, would establish a dangerous precedent and a new and discriminatory obligation on this particular pipeline permit applicant and potentially on all future Part 4 applications.

The Board believes that in considering an application under the Pipeline Act, it may examine and investigate any matter relating to the economic, orderly, and efficient development in the public interest of pipeline facilities in Alberta, and relating to the control of pollution and conservation of the environment in the development and operation of pipeline facilities, as set out in section 5, Part 3 of the Pipeline Act. Moreover, any application before the Board comes under the provisions of the Energy Resources Conservation Act. Section 2 of that Act sets out the purposes of which (c), (d), and (e) seem most pertinent to this question, viz:

(c) to effect the conservation of, and to prevent the waste of, the energy resources of Alberta;

(d) to control pollution and ensure environment conservation in the exploration for, processing, development and transportation of energy resources and energy;

(e) to secure the observance of safe and efficient practices in the exploration for, processing, development and transportation of the energy resources of Alberta;

Accordingly, the Board believes that in addition to assessing the technical aspects of the specific applications pursuant to the requirements of Part 4 of the Pipeline Act and the Pipeline Regulations, it may also have regard to the issues of economic, orderly, and efficient development. In doing so, the Board does not believe that it is establishing any new obligations on an applicant for a pipeline permit, and, on the contrary, holds the view that such obligation is implicit with each such application.

4 ISSUES

In considering the application, interventions, and evidence provided at the hearing, the Board sees two broad categories of issues that must be examined to arrive at a sound basis for determining the disposition of the Gulf applications. The two categories are:

(a) the suitability of the pipeline facilities applied for, and

(b) the implications of tying in and placing the 8-1 well on production at this time in relation to the economic, orderly, and efficient development of the Caroline Swan Hills Pool, including safe and environmentally acceptable production, transportation and processing.

In the Board's view, applications for the proposed pipelines must reasonably accommodate concerns and issues arising in both categories in order to be eligible for approval.

5 SUITABILITY OF THE PIPELINE FACILITIES

The Board considers the issues respecting the pipeline applications to be

o the need and purpose for the proposed pipelines,

o the design of the pipelines, and

o the acceptability of the proposed route and tie-in point.

5.1 Need and Purpose

Gulf stated that the 8-1 well has been drilled and completed and that it has an existing market for the gas products that could be recovered. It also indicated that the well could be produced at limited rates by utilizing the existing Garrington-Lanaway pipeline system and by utilizing the spare capacity at the Gulf Strachan gas plant (see Figure 1).

Gulf pointed out that staged development, including preliminary production at a limited rate from the 8-1 well, would reduce the possibility of facility design errors or redundancies when full-scale development was undertaken. Its program would involve investments of only some 3 million dollars and only 15 km of new pipelines. In return, operational experience of considerable value to all parties could be obtained.

Shell did not agree with Gulf's point of view regarding the value of the information obtained from the 8-1 well and contended that there would be minimal benefits from production of the 8-1 well compared to short well-site capability tests that are now conducted. Shell believed that timing of such production should be weighed against other factors including minimizing environmental impacts.

Union Pacific pointed out that not producing from the 8-1 well would not result in the loss of the lease. It therefore stated that no contractual obligation exists that would necessitate production of the 8-1 well in the immediate future.

The Board notes, and on this there is no disagreement, that Gulf has a right, subject to relevant legislation, to place the 8-1 well on production in order to win the resources within the spacing unit. Clearly, therefore, the pipeline facilities would be necessary to transport the raw gas from the well to a point where the raw fluids could be processed for marketing. The Board concludes that there will be a need for pipeline facilities to permit production of the 8-1 well and agrees that the applied-for facilities could serve that purpose. Whether those are optimum and would continue to be utilized in relation to large-scale development of the field falls under the Part (b) category of issues and is addressed in Section 7 of this report.

5.2 Design and Capacity of Pipelines

Gulf stated that the productive capacity of the 8-1 well was 700 x 10^3 m^3/d of raw gas. It also stated that the applied-for sour gas pipeline was designed for approximately 700 x 10^3 m^3/d. However, because of regulated sour gas limitations on the Garrington-Lanaway system, it would be eligible to produce only at some 140 to 280 x 10^3 m^3/d of gas from the 8-1 well through the proposed pipeline. Gulf also indicated that it expected hydrocarbon liquid production of some 160 m^3/d (1000 bbl/d) at an average raw gas production rate of 140 x 10^3 m^3/d. Gulf stated that facilities would be installed at the compressor station to accommodate operating problems due to liquid transportation. Alternatively, consideration was being given to installing separation equipment at the 8-1 well and constructing two pipelines to transport the gas and the liquid separately to the compressor station. Gulf recognized that a separate application would be necessary for this purpose.

Gulf stated that the maximum incremental sour gas volume that the Garrington-Lanaway pipeline could accommodate from the proposed pipeline would be 280×10^3 m^3/d because of the H_2S release volume limitations. It indicated that major modifications to the Garrington-Lanaway pipeline system would be necessary to transport larger quantities. Therefore, while it considered the Garrington-Lanaway system as a potential corridor to move larger quantities of raw gas and liquid to the Strachan plant, such changes would have to await future applications.

Gulf acknowledged that the pipeline facilities applied for would be only sufficient to accommodate production from its 8-1 well and possibly another anticipated well at Lsd 16-34-35-6 W5M (16-34 well). As a result, other pipelines to tie in other wells such as Shell 5-32-35-5 W5M would require separate applications.

Gulf stated that the Strachan gas plant could handle up to 700×10^3 m^3/d of Caroline gas without modifications and up to 1400×10^3 m^3/d with minor modifications. It indicated that the Strachan plant was one of Gulf's most modern plants capable of achieving high recovery levels of natural gas liquids and sulphur. It stated that the plant equipment includes a tail gas clean-up facility which under current operation recovers 99 per cent of the sulphur. Gulf also stated the Strachan plant recovers 90 per cent of the propanes and butanes and essentially 100 per cent of the condensate in the gas stream.

Shell stated that an effective design for the pipelines in the area could not be accomplished until it is known what volumes are to be transported from this field and where they are to be processed for liquid and sulphur removal. It did not contest the capacities stated by Gulf for the Garrington-Lanaway pipeline system and the Strachan gas plant.

It appears that the applied-for sour gas pipelines would be of more than adequate size to meet Gulf's near term objective. In that respect the Board would see no reason to not grant the applications. The Board notes, however, that Gulf has not carried out its design plans to a sufficient stage where it would consider its intentions completely firm. That is, the applied-for gas and liquids commingled pipeline might still be amended to provide for separate gas and liquids pipelines. Such a design change would not, on the face of it, seem to raise related problems and apparently would allow ready conformance to sour gas setback restrictions, owing to the smaller quantities of sulphurous components in each line.

5.3 Route Selection

Gulf indicated that the applied-for pipeline route represents the optimum pipeline route in regard to the local country residential population (see Figure 2). Gulf stated that it was necessary to have the tie-in point at the Lanaway compressor station in order to utilize the gas-liquid separation facilities available at the site. It explained that the route from the 8-1 well to the compressor station had to avoid several public facilities including the Raven Brood Fish Hatchery, the Latter Day Saints Church, the Crammond Hall, and a large number of country residential properties. It submitted that three alternate routes had been considered and rejected because of their difficulties in meeting prescribed setbacks and difficult river crossings. Gulf also stated that its route selection accommodated landowners' concerns regarding future building sites, subdivision plans, recreational interests, and agricultural operations. Subsequent to the hearing, Gulf made some minor route adjustments to further accommodate landowners' concerns. It also pointed out that as the dominant land use is agricultural along the right of way, there would be minimal clearing of forested lands.

Gulf stated that, starting from the 8-1 well, the proposed pipeline would extend southward close to other potential drilling locations. Thus, it would facilitate a tie-in for prospective Caroline Swan Hills production from the 16-34 well that it planned to drill in the near future. It also indicated that the pipeline would be in close proximity to three Shell wells at Lsd 5-32-35-5 W5M (5-32 well), Lsd 7-28-35-5 W5M, and Lsd 10-15-35-5 W5M. Gulf indicated that it would be receptive to negotiating access to the proposed sour gas pipeline for purposes of testing other wells such as the Shell wells, while shutting in the 8-1 well. Alternatively, the route it had selected could serve as a common pipeline corridor to bring production from the above Shell wells to the Lanaway compressor station.

Shell's major concern was that conceivably neither the applied-for sour gas pipeline nor the connecting Garrington-Lanaway system would fit in with the long-range, full-scale development plan for the Caroline Swan Hills Pool. Provided they did, Shell would not take exception to the route selection.

Dome expressed the view that any decisions now taken by the Board should not preclude other alternatives in future.

The Board notes that Gulf has done extensive work on route selection in order to meet the setback requirements for its proposed sour gas pipeline while at the same time accommodating landowner concerns. In those respects, the Board believes the route selection is nearly optimum for the limited purpose of producing the 8-1 well and also possibly other nearby wells.

To the extent that the Garrington-Lanaway system might be modified to carry substantially increased quantities of sour gas and liquids, the applied-for sour gas pipeline would fit in with the concept of processing Caroline Swan Hills Pool production at the Strachan gas plant.

Given the foregoing outlook, the Board believes that Shell's concern about failure to conform with an overall field transportation plan is not sufficiently justified to deny the applications. By the same token, if the Garrington-Lanaway system is not upgraded (for whatever reason), the applied-for pipeline would only serve as a minor outlet for Caroline Swan Hills production. In that instance, the precautions taken by Gulf in its route selection, including setbacks and accommodation of landowners' concerns, will have proven more than adequate.

5.4 Board Findings on Pipeline Related Issues

The Board finds that the applied-for sour gas pipeline and related facilities meet the provisions of the Pipeline Act in terms of need and purpose, acceptable design, and suitability of route selection.

6 IMPLICATIONS OF PLACING THE 8-1 WELL ON PRODUCTION AT THIS TIME IN RELATION TO ORDERLY AND EFFICIENT DEVELOPMENT

6.1 Gulf

Gulf viewed the tie-in and commencement of production from the 8-1 well as an important early step in the orderly development of the Caroline area. It pointed out that the tie-in and production of the 8-1 well would

- provide more data on the composition of gas at the 8-1 well, which it believed differs considerably from other wells in the field,
- provide information necessary for the design of the well site gathering and processing facilities for the overall field development,
- establish certain reservoir parameters useful in unitization negotiations, such as pore volume and reservoir continuity,
- aid in the determination of appropriate well spacing for full-scale field development, and
- help in the formation of realistic long-term Caroline Swan Hills Pool development plans.

Gulf stated that production of the 8-1 well would not create any direct offset drilling obligations and may, by virtue of production performance information, actually reduce the number of wells that would ultimately be drilled.

Gulf contended that the 8-1 well tie-in would be compatible with future development as the pipeline route represented the optimum route with regard to population and environmental aspects in the immediate areas. Gulf argued that utilization of existing facilities (ie, the Gulf Strachan sour gas plant and the Gulf Garrington-Lanaway main sour gas pipeline) was consistent with orderly development and eliminated the duplication of facilities. It also presented evidence to illustrate that drainage of the reservoir would be minimal since the proposed production rate of $140 \times 10^3\ m^3/d$ over 5 years would recover only 10 per cent of the estimated in-place reserves in Section 8. Also, it offered the concept that "gas banking" could provide a method of protection for other owners against drainage by compensating the weighted tract factor by recognizing the production that would accrue at a well prior to unitization.

6.2 Shell

Shell contended that most of the benefits claimed by Gulf of early sustained production from the 8-1 well were not relevant to the development of a plan for economic, orderly, and efficient development of the field. Shell's view was that most of the information, such as reservoir fluid composition, was already well established and also that the high permeability of the pool was already confirmed by the consistent high productivity demonstrated in the seven wells already drilled and tested. Shell therefore believed that commencement of production of the 8-1 well at this time would have the opposite effect to that suggested by Gulf; namely, that it would run a high risk of tipping the scale toward more rapid but disorderly and potentially inefficient development with unnecessary drilling and field gathering facilities being installed. Shell implied that these actions would be translated into compound problems for landowners in dealing with individual applications since landowners would be faced with conflicting pictures of the directions for field development.

Shell believed that any scheme which is not part of a co-ordinated development would likely lead to an escalation in drilling activity to protect the rights of adjoining mineral lease and royalty holders against drainage. It maintained that applications for pipeline tie-ins of other wells could follow, and the sequence of drilling and tying in additional wells could have a cascading effect throughout the pool. The result would be rapid but disorderly development.

In summary, Shell claimed that competitive development could potentially result in unnecessary surface impacts, inefficient facilities and wasteful investments, as well as opposition by landowners. It contended that the Gulf scheme should be evaluated to ensure that it is compatible with full field development, and in that regard considered the Gulf application seriously deficient since at the present time, options for full field development are not known.

In response to questions of timing, Shell indicated that a deferral of the Gulf applications of 6 to 7 months would be enough time to obtain agreement from the involved parties regarding an overall scheme for this field. If the Gulf applications did fit in with that plan, there would be good reasons to grant them.

Shell acknowledged, however, that availability of processing capacity was a critical factor in the development of an overall plan. For example, dedication of perhaps 1400 x 10^3 m^3/d to Gulf's Strachan plant and a similar rate to Canterra's Ram River plant would still leave 5600 x 10^3 m^3/d to be processed in either a new plant or expansion of another plant in the vicinity. Plant ownership and cost considerations would be major factors in any overall plan. Shell therefore believed that it would take upwards of 16 months to establish where other major facilities would be located.

6.3 Union Pacific

Union Pacific supported Shell's position regarding timing of production of the 8-1 well. In addition, Union Pacific pointed out that if Gulf placed the 8-1 well on production, Shell may put its 5-32 well on production, thus creating a concern about drainage in sections 29 and 31 and an offset drilling obligation in section 31. Union Pacific explained that it holds an interest in 8.5 freehold sections in township 35, range 5, W5M under PanCanadian Petroleum Limited (PCP) freehold leases and that each PCP freehold lease contains an offset drilling obligation which requires the lessee to commence drilling a well within 10 days after a well on a laterally adjoining drilling spacing unit has produced in commercial quantities for 90 consecutive days, on penalty of losing the productive zone(s) under the PCP freehold lease for non-compliance. Union Pacific estimated that, if the Gulf applications were granted, its contractual drilling obligations in section 31 could arise in 9 months, on the assumption that Shell may require 6 months to tie in its 5-32 well. Under the above circumstances, it would proceed to drill and tie in wells in sections 29 and 31. Union Pacific acknowledged that unitization would eliminate the offset drilling obligations and the concerns about drainage. However, it stated that it would prefer that the Gulf applications be deferred for a reasonable period of time for an overall field development strategy to be developed by all potential working interest owners in the Pool.

6.4 Canterra

Canterra did not take a position with respect to whether the application should be granted or denied. It noted that joint planning by Canterra, Shell, and Gulf was at a preliminary stage and remarked that it was in each party's self-interest to advance this planning. It anticipated that the result of this planning would be a number of applications for facilities before the Board.

6.5 Dome

Dome stated that its major concern was that the Caroline Swan Hills Pool be developed in an orderly and efficient fashion. It voiced the opinion that nothing should be done at this time that would preclude any of the future potential or future development options for this pool. Although it said that Shell's intervention raised some valid points, it did not actively support Shell's position.

7 BOARD CONCLUSIONS RESPECTING THE IMPLICATIONS OF PLACING THE 8-1 WELL ON PRODUCTION AT THIS TIME IN RELATION TO ECONOMIC, ORDERLY, EFFICIENT, SAFE, AND ENVIRONMENTALLY ACCEPTABLE DEVELOPMENT OF THE CAROLINE SWAN HILLS POOL

The Board agrees with Shell and Union Pacific that availability of a general plan for development of the Caroline Swan Hills Pool, including identification of probable well sites and numbers of wells, pipeline corridors, and preliminary dedication of process plant capacities at Strachan, Ram River, and other sites, would lay the groundwork for other desired planning. This would be especially advantageous in order to minimize adverse environmental and land use effects while assisting in promoting orderly, efficient development. It seems likely, however, that upwards of 6 to 7 months could elapse before such a plan is produced, and even then, changes to local pipeline transportation routes could occur as a result of new reservoir information or accommodation of landowner concerns. In the circumstances, the Board must consider whether the tie-in and commencement of production of the 8-1 well should be delayed pending determination of process facilities, wells, and pipelines that would be optimum for full-scale production. The Board thinks not, because the 8-1 tie-in involves only a 15-km pipeline connecting to an existing main pipeline and process plant facilities. The surface impacts are incrementally modest and have received general landowners' acceptance.

The Board must next consider whether there are other reasons why the 8-1 pipeline tie-in should be deferred. The major question is whether or not the proposed pipeline and the resultant production of the 8-1 well would cause a rash of competitive drilling and proliferation of surface facilities. To evaluate the possibility, the Board has considered the probable time frames for development of the pool from its present stage to ultimate full-field development and production at a level which was generally agreed to be as much as 8400 x 10^3 m^3/d by about the year 1992.

The approach advocated by Shell contemplates that approximately 6 to 7 months would be required to develop a conceptual plan for pool development, and an additional 9 months to reach some measure of agreement on major facilities among the various working interest owners. By this approach, a further period of some 3 years would be required to design and build appropriate facilities for transportation and processing to accommodate the full-pool depletion rate.

The Gulf proposal calls for staged development, with initial production at about 140 x 10^3 m^3/d, then a step up to some 1400 x 10^3 m^3/d (perhaps being production dedicated to the Strachan plant), and finally to an ultimate level of 8400 x 10^3 m^3/d by 1992.

The Board's view is that the first 2 years or so of production at relatively low rates at the 8-1 well, from a pool of such magnitude, would not have significant drainage or conservation impacts. Moreover, the availability of a "gas banking" contractual arrangement should obviate the need for Shell to place the 5-32 well on production and hence not trigger offset drilling obligations on the laterally contiguous Union Pacific lands or other disorderly development. Furthermore, at about year five on both the Gulf and Shell proposals, all necessary production, pipelining, and processing facilities would be in place to allow full-scale depletion rates to proceed. This leaves an intervening period, perhaps years two to four, after commencement of 8-1 production, when competitive production under the Gulf-staged concept might rise to 1400 x 10^3 m^3/d. This the Board considers to be the critical interval where the possibility exists that disorderly development, land-use conflicts, and negative impacts on conservation and correlative rights might become especially troublesome. To avoid this potentially troublesome period, preparation of an overall development strategy within the first 2 years is essential.

In summary, focusing once again on the initial 1- to 2-year period, the Board is of the view that placing the 8-1 well on production at this time and at the limited rates proposed by Gulf would not likely cause a rash of disorderly drilling and pipeline construction programs by other operators. Meanwhile, all working interest owners will have time to look at different development scenarios. If the overall development options are settled, all working interest owners would be in a position to plan and proceed with their activities, including the drilling of development wells, or in lieu thereof, unitization of lands to avoid unnecessary drilling, and completion of arrangements for transportation, processing, and marketing that serve their interests. The Board agrees with the major participants that with dedicated effort these plans could reach an advanced stage of completion over the next 2 years or so. Over that period, with appropriate interchange of information, all stakeholders would be better able to determine what measures should be applied to ensure that orderly, efficient, safe, and environmentally sound development would occur. The Board endorses such concepts that could assist in mitigating drainage effects resulting from competitive operations including "gas banking", enlarged spacing units, or the development of local unitization agreements.

8 BOARD CONCLUSIONS

The Board concludes that the Gulf applications for pipeline facilities that will allow it to tie in the 8-1 well and place it on production at limited rates reasonably accommodate the concerns and issues arising under the two broad categories set out in Section 4 of this report, namely:

(a) suitability of the pipeline facilities, and

(b) conformance with economic, orderly, and efficient development.

The conclusion is subject to the condition that the maximum annual average throughput rate in the sour gas pipeline shall not exceed 140 x 10^3 m^3/d.

9 PUBLIC INVOLVEMENT

Even recognizing the Board's decision to grant the Gulf application, the Board believes it appropriate to emphasize at this time that planned, co-ordinated development of the majority of the facilities within this large sour gas pool is essential. The Board strongly encourages the operators in the area to form a Caroline area development and environmental planning group. Such a group would include representatives of industry, government, local landowners and residents, and others. It could carry out background information gathering, monitoring, co-ordinated and co-operative planning to minimize environmental impacts, and consistent public communication programs, and could provide advice to industry, landowners, government, and the Board on potential environmental and social impacts. The appropriate parties would then be in a better position to act with confidence to minimize and mitigate such impacts.

The Board believes that such a group should be established and be in a position to assist the operators in bringing forward a pool development plan within the next 6 months. However, the Board is optimistic that industry will recognize the distinct advantages of proceeding expeditiously with this kind of plan.

10 DECISION

Subject to the approval of the Minister of the Environment, the Board grants the pipeline permits subject to the condition that the maximum annual average throughput rate in the sour gas pipeline shall not exceed 140 x 10^3 m^3/d.

DATED at Calgary, Alberta, on 27 November 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom
Vice Chairman

R G Evans

R. G. Evans
Acting Board Member

Antonio

H. Antonio
Acting Board Member

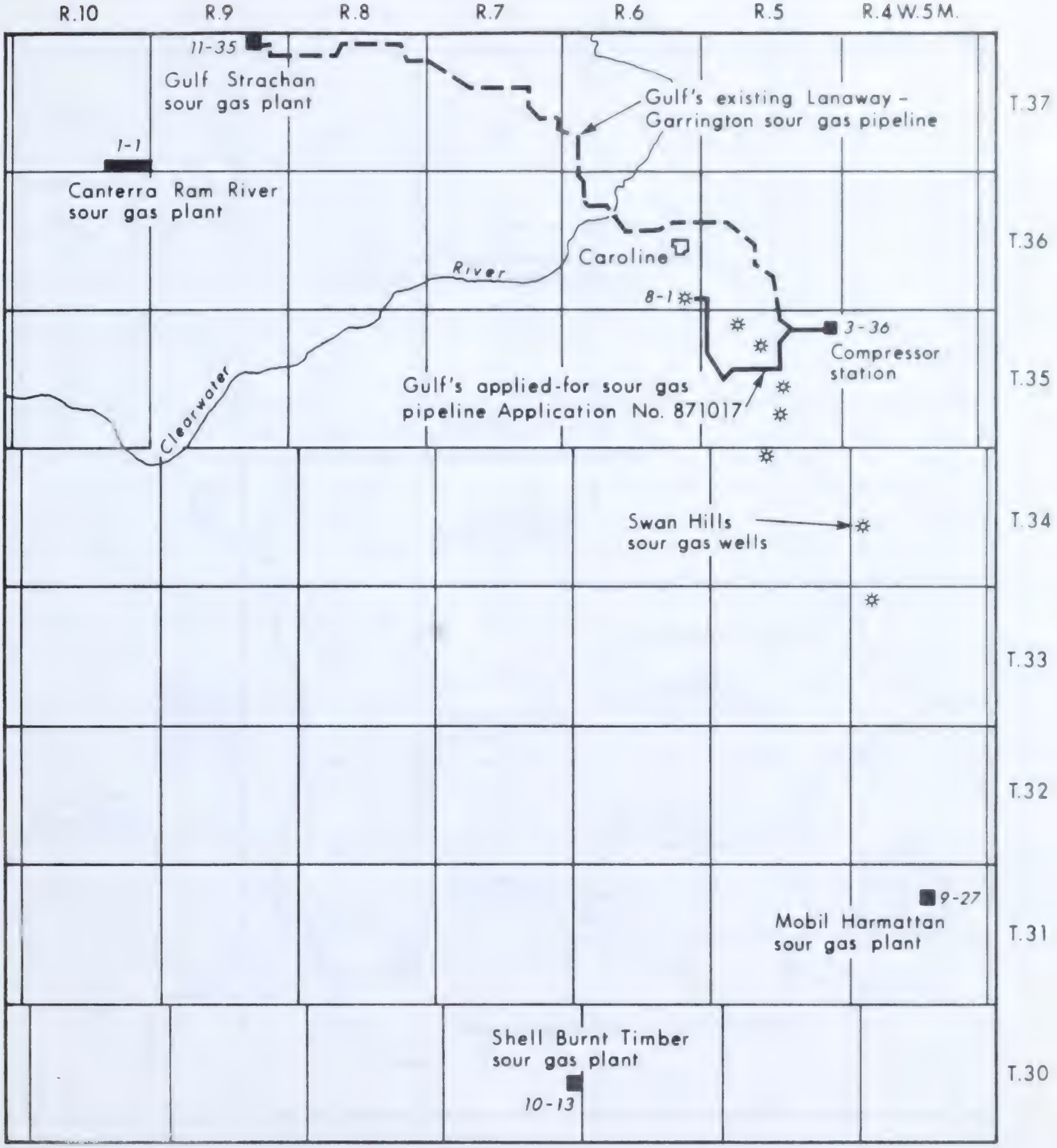

R.10
R.9
R.8
R.7
R.6
R.5
R.4 W.5M.
T.37
T.36
T.35
T.34
T.33
T.32
T.31
T.30
11-35
Gulf Strachan sour gas plant
Gulf's existing Lanaway - Garrington sour gas pipeline
1-1
Canterra Ram River sour gas plant
Caroline
River
Clearwater
8-1
3-36
Compressor station
Gulf's applied-for sour gas pipeline Application No. 871017
Swan Hills sour gas wells
9-27
Mobil Harmattan sour gas plant
Shell Burnt Timber sour gas plant
10-13

FIGURE 1 APPLIED-FOR PIPELINE ROUTE
Application No. 871017
Gulf Canada Corporation

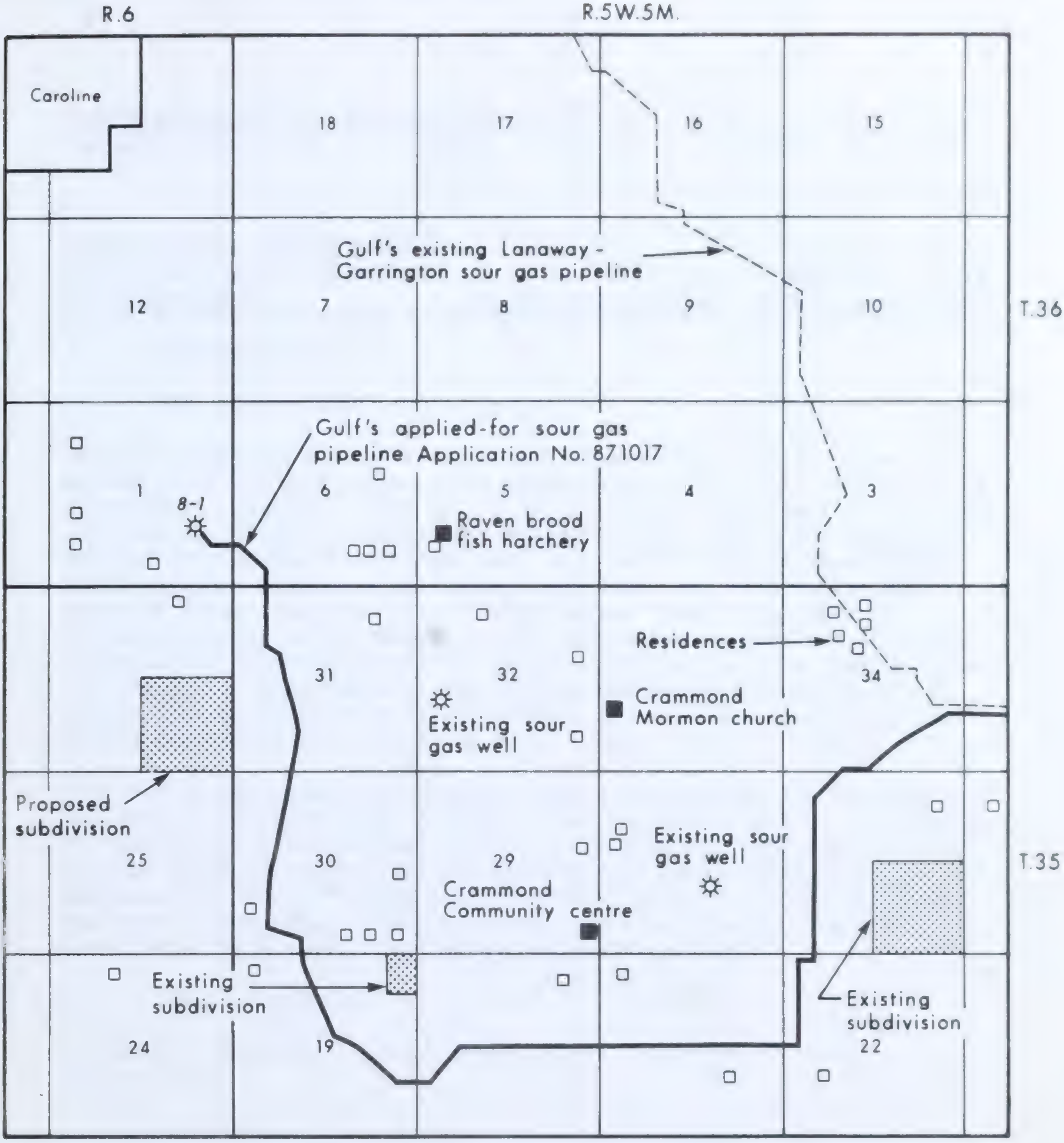


FIGURE 2 APPLIED-FOR PIPELINE ROUTE
Application No. 871017
Gulf Canada Corporation

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

UNION PACIFIC RESOURCES INC.
SPECIAL GAS WELL SPACING Decision D 87-18
FERRYBANK AREA Applications 860247, 860248, and 860249

1 INTRODUCTION

1.1 The Applications

Champlin Canada Ltd. (now Union Pacific Resources Inc.) in three applications applied for an order establishing fractional section 16 of township 44, range 28, west of the 4th meridian (fractional section 16) (Application 860247), fractional section 28 of township 44, range 28, west of the 4th meridian (fractional section 28) (Application 860248), and fractional section 4 of township 45, range 28, west of the 4th meridian (fractional section 4) (Application 860249), as special drilling spacing units (DSUs) for the production of gas from all zones. Target areas would be within the central part of the DSUs, having sides 150 metres (m) from the east and west boundaries of the DSUs and parallel to them, and having sides 300 m from the north and south boundaries of the DSUs and parallel to them.

The subject fractional sections are intersected by the 5th meridian and are some 70 per cent smaller in area than a normal gas DSU, being about 75 hectares (ha) rather than 256 ha. Therefore, in accordance with section 4.050 of the Oil and Gas Conservation Regulations (the Regulations), Union Pacific Resources Inc. cannot drill any wells for the development of gas reserves until each fractional section is established as a special DSU with a unique target area.

1.2 The Intervention

PanCanadian Petroleum Limited submitted an intervention to the applications.

1.3 The Hearing

The applications were considered at a public hearing on 14 and 15 October 1987, in Calgary, Alberta, by a division of the Board comprised of N. A. Strom, P.Eng. (Chairman), and Acting Board Members H. Antonio, P.Eng. and M. J. Bruni.

Those who appeared at the hearing and abbreviations used in this report are listed in the table below.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Union Pacific Resources Inc. (Union Pacific)	L. Malowany, P.Eng.
J. Curran	T. Wiechart, P.Eng.
	B. Bowersock, P.Eng.
PanCanadian Petroleum Limited (PanCanadian)	B. G. Martin, P.Eng.
P. R. Murray	A. A. Hartling, P.Geol.
	P. J. Haugen
Energy Resources Conservation Board staff	
C. C. South	
M. Connelly	
K. Fisher	

2 CONSIDERATION OF THE APPLICATIONS

2.1 Views of Union Pacific

In January 1984, Union Pacific successfully obtained Petroleum and Natural Gas leases from the Crown for the development of hydrocarbons under each of fractional sections 16, 28, and 4. It subsequently completed a successful Glauconitic well in legal subdivision 8-10-45-28 W4M. Considering geological mapping in the area indicating gas potential in offset fractional sections, it now preferred to independently develop its equity in those fractional sections. Union Pacific therefore applied to the Board for an order establishing each of the fractional sections as a special DSU for the development of gas reserves (as shown in Figure 1), as required by section 4.050 of the Regulations.

In order to address issues of equity and drainage resulting from the establishment of the special DSUs, Union Pacific proposed that gas production rates from wells on the special DSUs be limited by multiplying the maximum well productivity (the absolute open flow (AOF) potential rate of the wells) by the ratio of the area of each fractional section to the area of a normal gas spacing unit (as set out in Appendix I). Union Pacific submitted that the AOF rate-based formula would recognize the quality of reserves being developed while reducing the effect of drainage to offsetting lands, permitting other mineral owners adequate opportunity to independently develop gas reserves. As an alternative, the applicant considered a reserve-based formula with some commonly accepted deliverability-to-reserves ratio as a basis for assigning a maximum production rate limit to the fractional sections. However, it rejected this concept as it expected that a reserve estimate would be subject to conflicting mapping interpretations and also would be likely to change over the life of a well as more reservoir data was acquired.

Union Pacific suggested that wells drilled on each of the fractional sections and adjoining full sections could result in the increased recovery of overall reserves because of a lower average abandonment pressure in the combined lands. In response to questions, Union Pacific pointed out that it would be prepared to proceed with drilling wells in the fractional sections provided that the assigned rate limit for the wells was not less than a minimum rate of 14 thousand cubic metres per day (10^3 m^3/d).

Union Pacific also considered, as a method of obtaining a share of production from the fractional sections, the creation of an enlarged special DSU consisting of a fractional section and an adjoining full section. Union Pacific submitted, however, that the establishment of an enlarged DSU and the pooling of ownership within that DSU would be fraught with difficulties and would have the unacceptable effect of its having to share a part of its unfilled gas contract commitments. It believed that there would be little or no incentive for the mineral rights holders in adjoining full sections, especially those sections containing productive wells, to propose an enlargement of the adjoining standard spacing unit. Further, Union Pacific submitted evidence suggesting that a typical drainage area of a Mannville well in the areas offsetting the fractional sections ranges from 79 to 259 ha, thereby raising doubt as to whether a single Mannville well could fully deplete an enlarged DSU. Also, Union Pacific regarded some of the fractional sections as having higher potential than adjacent sections. Specifically, Union Pacific submitted that it considers that fractional section 4 is a better prospect for a Glauconitic well than the adjoining section 3-45-28 W4M. Thus, the reserves per hectare underlying fractional section 4 are expected to be higher than those of the adjoining section, making any acreage-based pooling arrangement undesirable. In conclusion, Union Pacific recommended that the proposed special DSUs be granted including the provisions for maximum daily rate limitations based on well AOF.

2.2 Views of PanCanadian

PanCanadian, a major holder of fractional and full sections adjacent to Union Pacific's fractional sections, agreed that Union Pacific should have the opportunity to develop the hydrocarbon reserves under fractional sections 16, 28, and 4; however, it had serious reservations about Union Pacific's proposed maximum rate based on an AOF test. PanCanadian did not believe that Union Pacific's proposal is fair to the rights of owners of adjacent acreage, nor that it promotes the efficient development of provincial resources. Further, PanCanadian noted that Union Pacific's applications do not meet any one of the four possible criteria for approval of reduced DSUs, as set out in section 4.030(3) of the Regulations.

PanCanadian proposed that rather than approving a special DSU smaller than that normally permitted, the Board should seriously consider whether or not the special DSU should in fact be larger than usual, consisting of a full section and each of the fractional sections (as shown in Figure 2). PanCanadian acknowledged that it would be difficult to encourage an owner of an adjoining section with a productive well in it to participate in an enlarged DSU. However, PanCanadian believed that the approval of an expanded DSU involving more than 256 ha would allow the mineral rights holder of fractional acreage the opportunity to develop the reserves under its acreage without infringing on the rights of adjacent mineral rights holders, and without encouraging economic waste. PanCanadian suggested that more wells would not increase overall pool recovery and submitted that Union Pacific had not provided adequate evidence to support its claim that a single Mannville well may not fully deplete an enlarged DSU. PanCanadian pointed out that if production experience showed that one well could not drain the entire enlarged DSU, the parties involved could then apply to the Board for a reduction in the spacing. PanCanadian submitted that it had presented its proposal of enlarged DSUs to the applicant prior to the hearing; however, Union Pacific chose not to pursue it.

Referring specifically to fractional section 16, PanCanadian indicated that should the Board permit the smaller DSUs for the fractional acreage, basing the maximum production on an AOF rate is not reasonable as it would allow full recovery of fractional section reserves in less than 1 year. PanCanadian proposed that other possibilities to allow an opportunity for fair recovery of reserves would be to establish a production rate on a reasonable rate-of-take based on reserves, or to establish a maximum volume of gas which would be produced from a well equal to the estimated reserves underlying the fractional sections. Under the latter, the mineral holder could produce this volume at whatever rate deemed appropriate.

PanCanadian concluded that its proposals of enlarged DSUs or a reserve-based rate limiting formula would permit the applicant the opportunity of recovering its share of production while still honouring the basic objectives of orderly, economic development as set out in the Oil and Gas Conservation Act (the Act). Noting that it also is a holder of numerous fractional sections, PanCanadian submitted that it was putting forward specific proposals for consideration in the hope that some clear guidelines with respect to the fractional sections could be established.

2.3 Views of the Board

The Board recognizes the issue put forward by PanCanadian, that Union Pacific's applications have not fully satisfied any one of the four possible criteria for reduced DSUs, as set out in section 4.030(3) of the Regulations. Union Pacific argued that, in considering whether or not the applications have satisfied the requirements of the Act and the Regulations, the Board might primarily take into consideration section 4.050 of the Regulations which provides that any person proposing to drill a well in a fractional section shall apply to the Board for a special DSU if the proposed DSU differs in size from an ordinary DSU by more than 5 per cent.

The Board believes that criteria under section 4.030(3) must be satisfied, and in addition that the applications must be considered in relation to the general objectives of the Act, namely, sections 4(c) and (d):

> "4. The purposes of this Act are
>
> (c) to provide for the economic, orderly and efficient development in the public interest of the oil, gas and crude bitumen resources of Alberta;
>
> (d) to afford each owner the opportunity of obtaining his share of the production of oil or gas from any pool or crude bitumen from any oil sands deposit."

There are three possible rulings which could afford Union Pacific the opportunity of obtaining its share of the production of gas underlying its fractional sections, those being:

(a) To approve Union Pacific's request for special gas DSUs consisting of each of fractional sections 16, 28, and 4, with the rate of gas production from the special DSUs and target areas limited by the applicant's proposed formula as set out in Appendix I.

(b) To approve Union Pacific's request for special gas DSUs in part, by limiting production from the special DSUs using the Board's standard off-target penalty formula as set out in Appendix II.

(c) To deny Union Pacific's request for the special fractional gas DSUs with the view that the option of pursuing a larger than normal gas DSU consisting of each of the fractional sections and an adjoining full section is available to the applicant.

PanCanadian's proposal of limiting production from the fractional sections using a reserve-based formula would be a variation of either (a) or (b).

Possibility (a) would afford the applicant the opportunity of independently developing its gas reserves from each of the fractional sections. However, on the evidence provided, there would be substantial possibility of unfair drainage of reserves under sections adjoining the fractional sections. As well, approval of the smaller than normal gas DSUs could result in the drilling of unnecessary wells which would not conform with the objective of economic and efficient development.

Possibility (b) would reduce the potential for drainage of reserves underlying sections adjoining the fractional sections. However, the Board notes that the limiting production rate could be less than the minimum economic rate put forward by Union Pacific. In that case the wells would not be drilled and indirectly the applicant would be prevented from obtaining its share of gas production from the fractional sections.

Possibility (c) would eliminate the potential for unfair drainage of reserves underlying the sections adjoining the fractional sections, and also avoid the potential for the drilling of unnecessary wells. The Board notes Union Pacific's concern that there may well be little or no incentive for the mineral rights holders in the adjoining full sections, especially those sections containing productive wells, to voluntarily pool such a section with the adjoining fractional section, or enter into any other arrangement under which Union Pacific may share in production. However, Union Pacific has recourse in that it can apply for an order establishing enlarged DSUs and file an accompanying application for an order establishing the pooling of ownership in those DSUs. This was the approach that seemed to be favoured by PanCanadian.

In dealing with fractional sections, the Board's general view is that where the size of the fractional section is not considerably smaller than the size of the normal gas DSU, and is such that the target area requirements set out in section 4.020(3)[1] of the Regulations can be applied, it is appropriate to establish a smaller than normal gas DSU consisting of the fractional section. However, where a fractional section is significantly smaller than the normal gas DSU, and is such that the target area requirements set out in section 4.020(3) of the Regulations cannot be applied, it seems much more appropriate to establish an enlarged gas DSU consisting of the fractional section and the adjoining full section. In those instances where adequate evidence is provided which fully satisfies one of the four possible criteria for approval of reduced DSUs, as set out in section 4.030(3) of the Regulations, however, the smaller fractional DSU might be granted. The Board concludes that Union Pacific did not provide evidence which would clearly satisfy any one of the four possible criteria for approval of such reduced DSUs. Bearing in mind as well that the fractional sections in question are little more than one quarter of the size of a normal DSU, other possibilities for their economic development would seem more appropriate.

---

[1] Section 4.020(3) of the Regulations denotes that the target area for a normal gas DSU is within the central part of the DSU, having sides 300 m from the sides of the DSU and parallel to them.

3 DECISION

For the reasons given in section 2.3 of this report, the Board denies the applications.

DATED at Calgary, Alberta, on 20 November 1987.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

Antonio

H. Antonio, P.Eng.
Acting Board Member

M. J. Bruni
Acting Board Member

APPENDIX I UNION PACIFIC'S PROPOSED MAXIMUM RATE LIMITATION (Q_{SDSU}) FORMULA

$$Q_{SDSU} = q \times \frac{A_{SDSU}}{A}$$

where: q is a sandface absolute open flow rate in thousands of cubic metres per day as determined from stabilized deliverability calculations;

A_{SDSU} is the area of the special drilling spacing unit in hectares;

A is the area of a normal gas drilling spacing unit (256 hectares).

APPENDIX II THE BOARD'S STANDARD OFF-TARGET PENALTY FORMULA (Section 4.070 of the Regulations)

Off-Target Penalty for a Gas Well = (Qmax for the well) x (Allowable Multiplier)

Off-Target Penalty is a current maximum annual allowable rate, recalculated annually by Board staff.

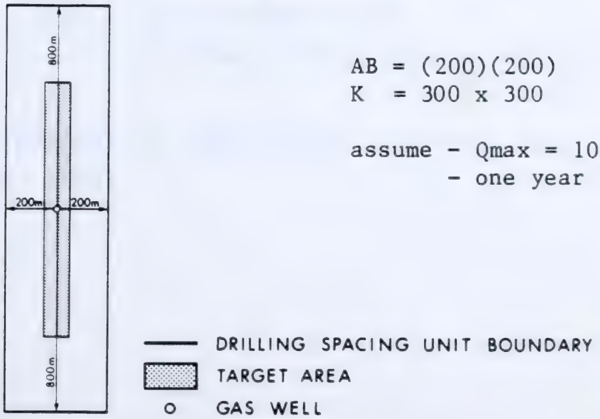
Qmax is a current maximum daily allowable rate calculated from the equation set out in section 10.300(1)(c) of the Regulations. The Qmax rate is recalculated annually by Board staff.

Allowable Multiplier is an off-target penalty factor calculated from the equation

$$\text{Allowable Multiplier} = 0.5\,\frac{AB}{K}$$

where: A and B are the distances measured in metres from the uppermost point of intersection, when the well is drilled, of the wellbore with the gas productive part of the producing pool to the two nearest boundaries of the drilling spacing unit plus, where such a boundary adjoins a road allowance, 10 metres; but A or B shall exceed the distance in metres from the side of the target area to the nearest parallel boundary of the drilling spacing unit only when the boundary adjoins a road allowance and, in such case, by 10 metres; K is 300 x 300 for a normal drilling spacing unit size for a gas well of one section.

Sample calculation with a well drilled in the exact centre of the target area.



AB = (200)(200)
K = 300 x 300

assume - Qmax = $100 \times 10^3\ m^3/d$
- one year = 365 days

$$\text{Off-Target Penalty} = [100 \times 10^3\ m^3/d] \times \left[0.5\ \frac{(200)(200)}{300 \times 300}\right] \times [365\ \text{days/year}]$$

The maximum annual withdrawal rate for the gas well would be $8111.1 \times 10^3\ m^3$.

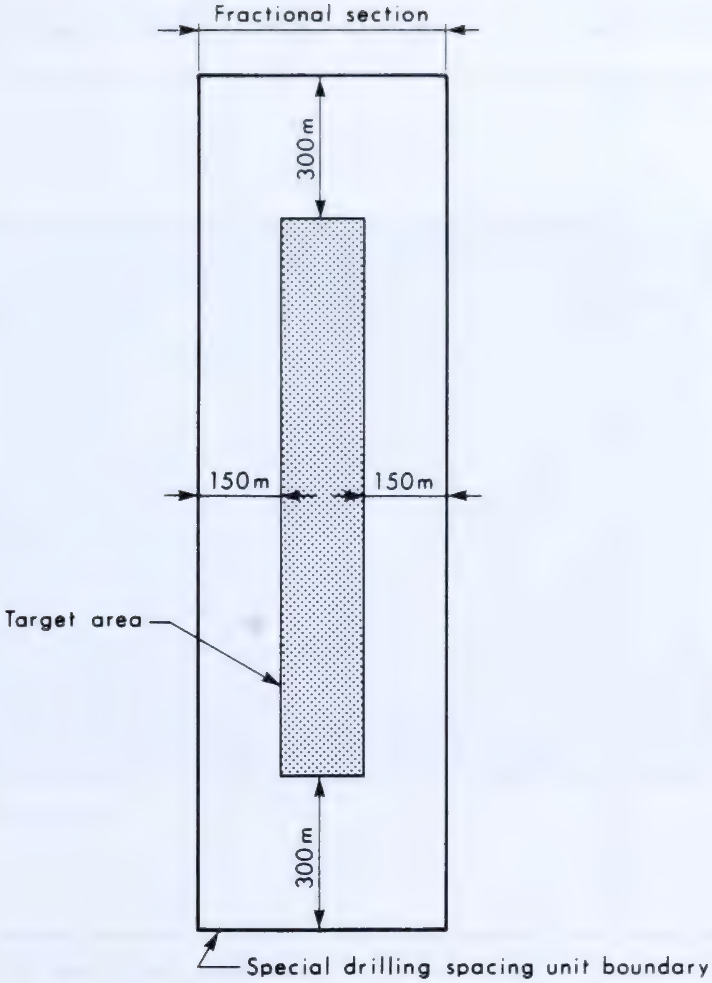


FIGURE 1 UNION PACIFIC'S PROPOSED SPECIAL DRILLING SPACING UNIT

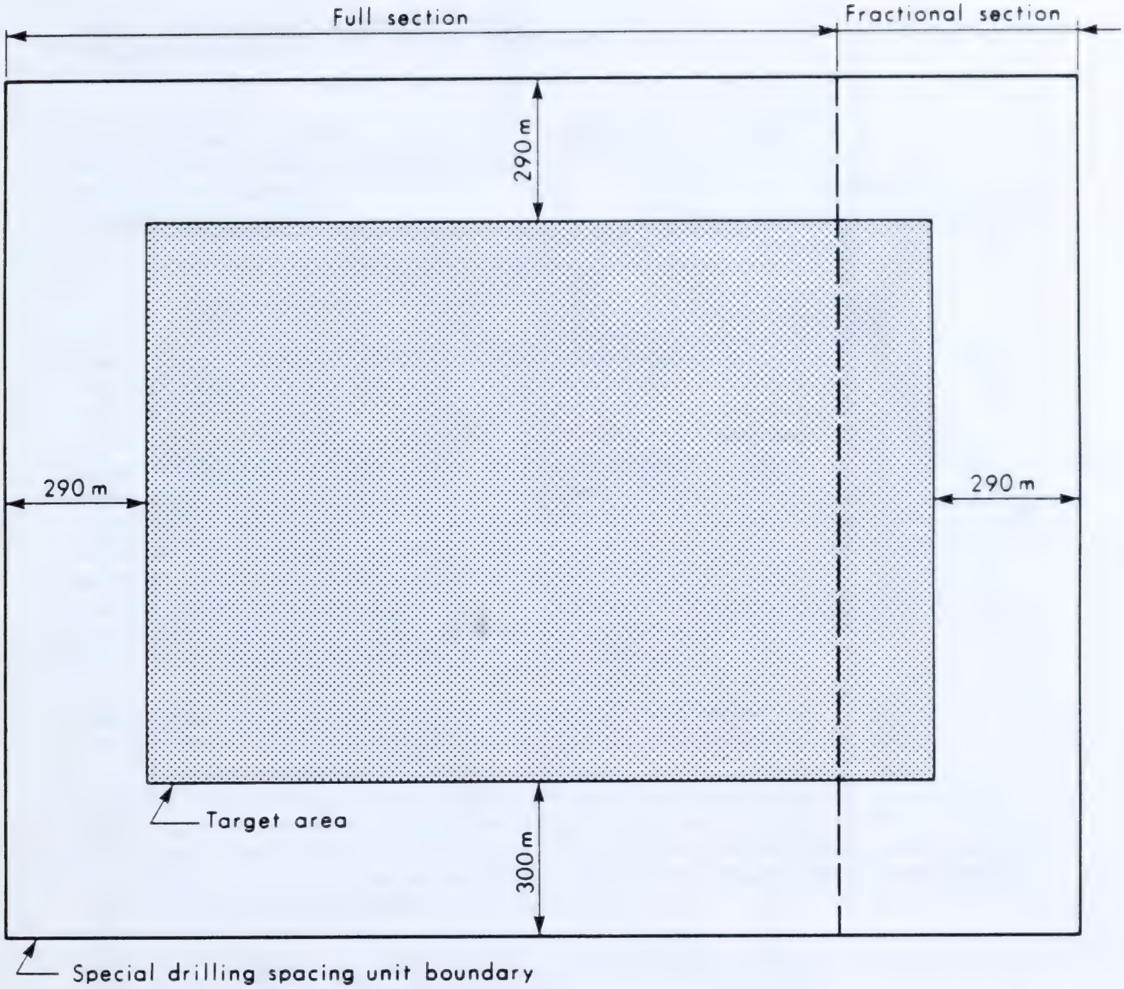


FIGURE 2 PANCANADIAN'S PROPOSED SPECIAL DRILLING SPACING UNIT

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

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SHELL CANADA LIMITED
SOLUTION GAS PROCESSING PLANT AND
CENTRAL OIL BATTERY
MANYBERRIES FIELD

Decision D 87-19
Application 871144

1 APPLICATION AND HEARING

Shell Canada Limited (Shell) applied, pursuant to section 26 of the Oil and Gas Conservation Act, and in accordance with sections 7.001, 7.002, and 15.050 of the Oil and Gas Conservation Regulations, for approval to construct and operate a central multi-well oil battery and a sweet solution gas processing plant in the Manyberries Field. The proposed multi-well oil battery and gas processing plant would be constructed in legal subdivision 7 of section 28, township 5, range 5, west of the 4th meridian (7-28 site). The gas plant would be designed to process a maximum of 58 thousand cubic metres per day (10^3 m^3/d) of currently flared sweet solution gas from the Manyberries Sunburst U, OO, and Q pools from which 52 x 10^3 m^3/d of sales gas and 19.5 m^3/d of liquefied petroleum gases (LPG mix) would be recovered.

Petro-West Engineering Ltd. (Petro-West) intervened on the issue of whether more than one plant was needed in the Manyberries Field.

A public hearing to consider Shell's application began in Calgary, Alberta, on 3 November 1987, with C. J. Goodman, P.Eng., J. P. Prince, Ph.D., and M. J. Bruni, sitting. Following an adjournment, the hearing continued on 3 and 4 December 1987. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) D. O. Sabey, Q.C. K. F. Miller	J. D. Kyles, P.Eng. W. A. MacLeod, P.Eng.
Petro-West Engineering Ltd. (Petro-West) S. Carscallen H. R. Hansford	
Home Oil Company Limited (Home) H. H. Hirschmanner	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Robinson Engineering Company Ltd., Pension Plan and Trust, and R. W. Robinson and Associates Company Profit Sharing Plan (Robinson) D. B. Reesor	
Energy Resources Conservation Board staff C.J.C. Page M. Semchuck, C.E.T. M. T. Pittman S. A. Brockhoff R. Florence	

Home appeared at the hearing and cross-examined Shell but did not present final argument.

Robinson registered at the hearing but did not participate actively.

2 BACKGROUND

The Manyberries Sunburst Q, U, and OO oil pools were discovered between 1978 and 1980. Currently these pools have about 40 oil wells capable of production. The U Pool is a single-well pool. The wells in the Q and OO pools produce to a number of single and multi-well batteries, and all of the solution gas is presently flared.

In May 1985, Petro-West, on behalf of CanAm Financial Group Ltd. (CanAm), submitted an application to the Board for approval to construct a sweet gas processing plant at 13-15-5-5 W4M (13-15). CanAm's facility was intended to process 140 x 10^3 m^3/d of solution gas which it stated would be gathered from a number of producers in the area including Anderson Exploration Ltd. (Anderson), Brinkerhoff Resources Inc. (Brinkerhoff), Home, Canadian Roxy Petroleum (Roxy), and Shell.

In September 1985, CanAm's Part I application for approval to construct the 13-15 plant was granted, and permits to construct the related gas gathering system (CanAm project) were issued to CanAm.

Following approval, CanAm retained Petro-West to build the facilities and Petro-West began constructing portions of the gas gathering system and carried out some preliminary site work at the 13-15 location for CanAm's plant. Construction reportedly continued while CanAm attempted to finalize arrangements to process the area producers' gas. Eventually, CanAm withdrew from the project while reportedly still owing Petro-West money for the construction that had been carried out and Petro-West apparently halted construction on the CamAm project. Although construction was started, the plant was never finished. Furthermore, at the present time some of the project's pipelines exist, some are partially constructed and left at surface, and some are not built.

Some of the solution gas produced from other pools in the Manyberries Field and area that was originally sought by CanAm to be processed through its 13-15 plant is currently being conserved and sold through the Canadian Montana Gas Company's (CMG) Manyberries gas gathering system.

3 INTERVENTION

Following advertisement of Shell's application on 29 September 1987, the Board received written objection from Petro-West stating it had gained legal rights to the CanAm project, the facilities were at an advanced stage of completion, and as a result there was no need for a second plant in the area.

The hearing was opened on 3 November 1987; however, Petro-West requested an adjournment claiming that it had just obtained some last-minute information and additional time was required to research this data, to acquire more data, and to contact possible witnesses for the hearing. The Board granted Petro-West's request and the hearing was adjourned until 3 December 1987.

Petro-West also requested that Shell be directed to produce certain documents relating to any contracts between CanAm and Shell. The Board denied this request.

When proceedings resumed on 3 December 1987, opening statements were presented by counsel for Shell and Petro-West. During cross-examination of Shell's application, counsel for Petro-West questioned Shell about the details of the negotiations between Shell and CanAm for Shell's gas and the processing of those gas volumes through CanAm's 13-15 facility. Counsel for Petro-West also attempted to file an exhibit which it alleged contained a series of documents that it believed would show that the raw gas reserves, which Shell intends to process through its 7-28 plant, are the gas volumes already dedicated to the CanAm project. Petro-West argued that, as a result of the previous negotiations and exchange of correspondence between Shell and CanAm, a contract committing Shell's gas to CanAm's project exists.

The Board disallowed the filing of the negotiation documentation by Petro-West. The Board stated its view that it was not within its jurisdiction to determine whether or not there was a contract between Shell and CanAm, and added that a ruling on such an issue is a question of law that should be pursued through the courts.

Following the Board's ruling disallowing the filing of correspondence between Shell and CanAm regarding their negotiations, counsel for Petro-West advised that it had made some preliminary inquiries about court time that may be available for contesting the issue of gas ownership in the courts. Counsel claimed that court proceedings to resolve this issue could commence in late April 1988 and requested that the hearing on Shell's 7-28 scheme be adjourned until the matter of gas ownership and gas contracts was resolved in the courts. The Board denied Petro-West's request for such an adjournment.

Following the Board's ruling disallowing an adjournment, Petro-West advised that it would not continue to cross-examine Shell on the 7-28 gas plant application, nor would it present any witnesses or provide direct evidence to support its claim that Shell's application would be a competing gas processing scheme to the CanAm project. However, prior to the closing of the hearing Petro-West did present final argument.

4 ISSUES

The Board considers the issues regarding Shell's application to be

- early conservation of solution gas,
- need for the plant, and
- plant size and location.

5 EARLY CONSERVATION OF SOLUTION GAS

Shell stated that upon approval of its multi-well oil battery and sweet solution gas processing plant, it would require 1.5 months to complete the multi-well oil battery and an additional 2 months to construct the gas plant. Shell stated it had already placed orders for a compressor and all the required plant processing components and that the delivery date for all the equipment was mid January 1988. Shell said that it could conserve gas immediately after completing construction of the battery and plant because it had executed a sales gas contract with CMG. At the hearing Shell undertook to provide evidence of its gas contract to all hearing participants and it has now fulfilled that undertaking. Shell stated that all its pipelines, including the sales line, are already constructed and are presently awaiting hook-up at the points of origin and destination. Shell added that the remaining hook-up would require a minimal amount of time.

Shell stated that it had visited the CanAm plant site area and various pipelines in October 1987. During its visit Shell took pictures of the various facilities and presented those pictures, a narrative description of what the pictures depicted, and its response to questions about the facilities, at the hearing. Shell estimated that the work completed by Petro-West as of October 1987 would have taken approximately 10 to 14 days to perform.

Shell estimated that the partially constructed pipelines (those lines still exposed at surface) would likely require an additional $100 000 to repair. Shell indicated that the pipe coating had deteriorated because it was exposed to the elements and as a result this pipe would have to be removed in segments and taken to a coating facility for upgrading and recoating before it would be usable. As for the buried pipelines, Shell stated that it would be more economical to abandon these lines in place than to attempt to salvage them, unless the lines could be used in place. Shell said that none of the lines that Petro-West had installed could be used for the Shell project as the buried lines were not constructed near the sources of feed gas to Shell's plant. Additionally, Shell questioned the integrity of the buried lines as it did not know if the pipelines had been hydrostatically tested. Furthermore, Shell did not know if the lines had been cathodically protected to prevent external corrosion or if any measures were taken to prevent internal corrosion of these lines. Shell could not estimate the cost of repairing the buried pipelines without conducting tests to determine what state they were in.

With respect to the overall CanAm project, Shell said that Petro-West, upon approval, would likely experience an equipment delivery period of 4 months, which is currently the typical waiting period for materials throughout the industry. Upon delivery of the equipment, Shell estimated that the construction period to complete a plant at 13-15 would require an additional 2 to 3 months.

Shell responded to questions on this evidence but Petro-West did not cross-examine Shell nor did it present any evidence in rebuttal.

The Board notes that CanAm was granted approval (Part I) in 1985 to construct a solution gas processing facility in the Manyberries Field. However, the CanAm project has not been completed and as a result solution gas continues to be flared. The Board believes that a plant is still required to conserve the presently flared solution gas as soon as possible. The Board notes Shell's position that its scheme would be operational in 3.5 months following approval of its project. The Board also notes Shell's assessment that Petro-West would require 6 to 7 months to complete the CanAm 13-15 facility after receipt of the Board's approval.

The Board notes that Petro-West would have to make application to the Board to have the pipeline permits and the gas plant approval which were issued to CanAm transferred to Petro-West. Petro-West has not made such application to date. Furthermore, a Part II application for approval to operate the 13-15 facility would also have to be submitted by Petro-West to the Board after the 13-15 facility has been completed.

Exhibit #8, which Shell submitted at the hearing, contained letters from Carlyle Energy Ltd., Congress Resources, Java Resources Ltd., Penn West Petroleum Ltd., and Roxy, area producers supporting Shell's 7-28 scheme. These producers claim that approval of Shell's application would expedite gas conservation and eliminate solution gas flaring in the Manyberries area.

The Board notes that both Shell and Petro-West stated that early conservation of the currently flared gas is the main objective of both parties and conservation is in the public interest. The Board agrees that it is in the public interest to conserve the gas as soon as possible.

6 NEED FOR A PLANT

Shell stated that its proposed facility would be designed to process a maximum of 58.0 x 10^3 m^3/d of raw gas which it estimated was the volume of economically conservable solution gas in the area of its 7-28 site. Shell stated that its 7-28 plant was needed to process the currently flared Shell-owned gas as well as the gas from other adjacent area producers.

Shell indicated that, commencing in 1985, it had held discussions with CanAm about having some of its gas processed at CanAm's 13-15 facility; however, it never did dedicate any of its gas to CanAm. It further indicated that when it had been unable to negotiate a suitable arrangement with CanAm, and after CanAm withdrew from its 13-15 project, Shell evaluated its processing requirements in the area and undertook to design and make application for its own gas processing scheme.

Shell stated that, if Petro-West elected to determine the matter of ownership of the solution gas through the courts, and if the courts determined that Shell had committed its gas to CanAm's project and a court order compelled Shell to give its gas to the CanAm project, Shell would remove its own gas processing facilities and reclaim the area.

Shell stated that the CanAm 13-15 facility, if completed, would be inappropriately sized, considering that the Home and Anderson gas volumes mentioned in CanAm's original application were no longer available and were currently being conserved and sold to CMG. Shell argued that the 13-15 facility would not operate efficiently at Shell's proposed solution gas inlet rate, and that the low plant throughput could cause flaring and disruption to normal plant operations.

In opening remarks by its counsel, Petro-West stated that the completion of the 13-15 facility is dependent on the dedication of Shell's solution gas volumes and that, without Shell's gas, completion of the 13-15 facility could not proceed. Petro-West stated it recognized that there is no alternative gas supply in the area, and it recognized that Shell is the major producer in the Manyberries Field.

Throughout the hearing, Petro-West argued that Shell's gas had already been committed to the CanAm project, and stated that it plans to take action through the courts to verify its claim. It requested that the Board's ruling on Shell's application be held in abeyance pending a court ruling on the ownership of Shell's gas.

Petro-West argued that there is no need for a second plant in the area of the 13-15 facility, which it claimed is near completion and could accommodate Shell's solution gas volumes.

The Board notes Petro-West's statement by its counsel that it retained an expert to determine if there was a gas supply for a plant in the Manyberries area and that the expert concluded that, except for Shell's gas, there was no other gas supply available for the 13-15 facility.

The Board acknowledges that the 13-15 facility, if completed, could accommodate Shell's anticipated solution gas volumes. It further acknowledges that, if Shell's gas is contracted to the CanAm project, Petro-West would be prepared to make application and complete construction of the 13-15 facility. However, as stated previously, contract determination is not within the ERCB's jurisdiction. Additionally, the Board is not prepared to allow economically conservable solution gas to be wasted when there could be a viable conservation scheme capable of effecting solution gas conservation within the first part of 1988. Should Petro-West choose to seek resolution of the gas ownership issue through the courts and should it be granted a favourable decision, the Board accepts that the 13-15 facility could be completed but doubts this could occur in a time frame that is comparable to Shell's 7-28 scheme.

The Board recognizes Shell's position that it is prepared to proceed expeditiously with its gas conservation and processing scheme completely at its own risk and, should Petro-West be successful in acquiring the rights to Shell's gas through the courts, Shell would dismantle and remove its processing facilities and restore the 7-28 gas plant area.

The Board also notes Shell's confirmation that it has obtained consent from area residents with respect to the construction and operation of its 7-28 facility, has obtained a development permit from the local county, and has also executed a sales contract for the gas with CMG.

The Board finds that Shell's 7-28 scheme is technically sound, that it would result in the earliest conservation of currently flared solution gas, and that it is environmentally acceptable. In this instance, and with the qualifications already stated, the Board believes there is a need for a gas processing plant as proposed by Shell.

7 PLANT SIZE AND LOCATION

Shell stated that its proposed plant, with a raw gas capacity of 58 x 10^3 m^3/d, would accommodate all the solution gas from the nine wells currently producing in the U and OO pools as well as the eight Shell-operated wells in the Q Pool which it would consolidate at its 7-28 multi-well battery. Shell added that it intended to make processing capacity available for all of the economically conservable solution gas in the area, and that the proposed 7-28 location is central to the producing wells. Shell stated that it designed its facility to process all the solution gas from the Q Pool once it was unitized and an enhanced recovery scheme was implemented. As it was already involved in unitization discussions with other Q Pool producers, it was confident that unitization would proceed and that, following an agreement, all Q Pool solution gas including Brinkerhoff's and Home's would be conserved through Shell's 7-28 plant. Shell stated that it did not foresee a need to have to expand its applied-for plant.

Shell believed the 13-15 site was too far removed from Shell's gathering system and proposed central multi-well oil battery to be considered as an alternative plant site. It further stated that CanAm's gas gathering system and sales lines were not appropriately sized or located for use in Shell's 7-28 scheme.

The Board believes that Shell's facility is appropriately sized to process all the economically conservable solution gas in the area and that Shell's 7-28 location is suitable for its central oil battery and processing facility. The Board notes that Petro-West acknowledged that the Shell gas is the only significant source of feed gas for a plant in the area; furthermore, the Board believes that processing capacity of 140 x 10^3 m^3/d, as proposed for the 13-15 facility, is no longer required for the Manyberries area.

The Board notes that Shell's plant would be on the same site as its central oil battery. It further notes that the 17 oil wells which are to be consolidated through satellites to the 7-28 battery are in closer proximity to Shell's 7-28 site than they are to the 13-15 site. The Board recognizes that battery consolidation is desirable as it would eliminate the trucking of crude oil from numerous single-well batteries. The Board also observes Shell's plans to install the multi-well battery and gas processing facility at the 7-28 site, as well as enhanced oil recovery facilities some time in the future. If the solution gas were to be collected at 7-28 and Shell's gas plant application denied, the solution gas would continue to be flared.

Petro-West did not cross-examine Shell on this evidence nor did it present any evidence in rebuttal. The Board accepts Shell's position that the proposed plant location is appropriate.

8 DECISION

Having considered all of the evidence, submissions, and argument, the Energy Resources Conservation Board is prepared to approve Shell Canada Limited's central multi-well oil battery and gas processing plant as described in Application 871144. Approval will be given on the understanding that Shell will implement conservation of solution gas at its 7-28 site by the earliest possible date.

DATED at Calgary, Alberta, on 15 January 1988.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DOME PETROLEUM LIMITED
APPLICATION FOR A WELL LICENCE
CAROLINE FIELD

Decision D 87-20
Application 871392

1 INTRODUCTION

1.1 Application

Dome Petroleum Limited (Dome) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations), for a licence to drill a well from a surface location in legal subdivision 14 of section 3, township 36, range 7, west of the 5th meridian, to a projected bottom-hole location in legal subdivision 4 of section 10, township 36, range 7, west of the 5th meridian. The proposed well, to be known as DOME ET AL CAROLINE 4-10-36-7 (the well), would be for the purpose of obtaining sour gas production from the Swan Hills Formation (Swan Hills).

1.2 Interventions

Interventions to the application were received by the Board from landowners and concerned persons in the vicinity of the proposed well. Those who appeared at the hearing to speak to their interventions are identified in the following table. The interveners generally did not take issue with the specific technical merits of the application but had a number of concerns respecting the potential negative impact during the drilling and operation life of a successful sour gas well in the area. The concerns included safety and environmental impact (noise, odours, and spills), public perceptions of safety and impacts from a nearby sour gas well, effects on land values, and intrusion into current lifestyles.

A representative of the Caroline Chamber of Commerce (the Chamber of Commerce) appeared at the hearing to make a statement in support of the application.

1.3 Hearing

A public hearing of the application was held on 17 November 1987 in Caroline, Alberta, before a division of the Board comprising N. A. Strom, P.Eng., F. J. Mink, P.Eng., and J. P. Prince, Ph.D.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Dome Petroleum Limited (Dome) R. A. Neufeld	D. A. Andrews, P.Geol. B. R. Croft, P.Eng. D. M. Huebner, P.Eng. S. E. Montgomery, P.Eng. R. E. Taylor, P.Eng.
Living Faith Evangelistic Association (Living Faith) C. A. Stalwick	D. Moyer C. A. Stalwick
Mr. and Mrs. L. C. Crawford (the Crawfords) C. Smart	C. Smart
Calvin Smart (Mr. Smart)	C. Smart
John Zigler (Mr. Zigler)	J. Zigler
Caroline Chamber of Commerce (the Chamber of Commerce) J. R. Dean	J. R. Dean
Energy Resources Conservation Board staff A. A. Broughton D. G. Beamer, R.E.T. D. K. Eresman, C.E.T. N. F. Lord, C.E.T.	

1.4 Background

The proposed well site would be located 400 metres (m) south of the Clearwater River (the River) at a point some 14 kilometres (km) west of the village of Caroline in west central Alberta. Title of the surface location for the proposed well site is held by the Alberta Crown. Although forestry and some agriculture exist in the area, the region is used significantly for recreational purposes containing numerous public and private campsites. Also, rural residential and recreational residential development along this portion of the River and nearby Alford Creek is prevalent.

Sour gas production in deeper horizons (Mississippian and Devonian) in the Strachan and Ricinus Fields some 10 km west of the proposed well has continued over the past 20 years. Also, shallower sweet oil present in the Cardium and Viking Formations has been produced from nearby pools (Garrington) for 25 years. Current interest is focused on the potential for developing deeper geological horizons with the Swan Hills being a primary zone of interest. The Swan Hills is gas-bearing in the area, generally is rich in natural gas liquids, and has a hydrogen sulphide (H_2S) component generally in the range of 35 per cent. Exploration drilling for the Swan Hills is primarily defined by seismic interpretation. Regionally the proposed well is located some 15 km on a northwest trend from the partly delineated Caroline Swan Hills Pool (Figure 1).

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for and purpose of the well,
- the location of the well,
- the drilling of the well,
- the production of the well, and
- impacts of the well on persons and offset lands.

3 NEED FOR AND PURPOSE OF THE WELL

3.1 Views of Dome

Dome submitted that, by virtue of a valid petroleum and natural gas lease, it had the right to explore for and recover gas reserves it believed to be present in the drilling spacing unit comprising section 10, township 36, range 7, west of the 5th meridian (the DSU). Dome stated that, it had a commercial, geological, and contractual need for the well. Specifically, a producing well would permit Dome a potential capital gain, geological information from the well would demonstrate if other possibilities for Swan Hills development existed, and Dome was required by the provision of the lease acquired in 1980 to drill a well by 1989 to maintain its lease in good standing.

Dome had initially scheduled to drill to prove or disprove its hopes for a productive Swan Hills in section 10 and thereby enhance its chances for a successful bid for the rights for the south adjoining section 3-36-7 W5M. However, with the land sale scheduled for late January 1988, it agreed that this objective was not now feasible as the earliest date for penetrating the potential production zone would likely be May or June of 1988 even if it obtained a licence before 1987 year-end.

3.2 Views of the Interveners

The interveners did not question Dome's right to the mineral rights under section 10 and generally accepted that oil and gas activity was a component of land use in the area. With the exception of the Chamber of Commerce which supported drilling the proposed well, they questioned the need for this specific well as compared to the impact it could have on their own needs.

Living Faith, whose centre is located approximately 2.5 km northeast of the well surface site, submitted that it had a compelling need to avoid adverse effects on its facilities and programs of activities.

Activities at its facilities and on its lands represented essentially its only source of financial support and its survival as an organization. By contrast, it implied that the applicant's relative needs for this well at this location could be minor, bearing in mind the widespread land holdings and operations of the company. At the same time, Living Faith acknowledged the general public benefit that derives from oil and gas resources development, and therefore held that as a practical matter the needs of the applicant and local land users would have to be assessed on a relative, rather than absolute, basis.

Mr. Zigler, whose quarter section of land is 1.5 km northwest of the well surface site holds three residences occupied by himself and his sons, questioned the need to extract the reserves from this DSU at this specific time. He recognized the general need for continued operations of the petroleum industry but drew attention to his needs as a landowner to protect his current residential and potential land-use situation.

Mr. Smart, who resides on and operates a small industry on his small acreage approximately 1.5 km northeast of the well surface site, suggested that there may not be a need to drain the Swan Hills reserves from a well to be bottomed in section 10. He argued that a well spacing different from the standard one well per section might be utilized as a means of reducing impacts on surface landowners. That approach might allow a well to be located farther away from the River valley and reduce perceived or real impacts on nearby intervener lands.

Mr. Dean, on behalf of the Chamber of Commerce, submitted that oil and gas activity in the area is a very positive factor increasing the growth and prosperity of the community. Given this, the Chamber of Commerce welcomed such activity and on that basis supported the Dome application.

3.3 Views of the Board

None of the interveners disagreed with the general need in the public interest to allow continued development of the province's oil and gas resources. They did, however, contend that sour gas development at this particular location could impose costs on themselves.

The Board recognizes Dome's need to pursue the possibility of recovering gas which may underlie section 10. Dome's need and the general public's interest must be weighed against the needs of those who may be directly and adversely affected.

The Board believes that the potential economic benefits of such developments heavily outweigh the likely economic costs on nearby surface landowners. In the circumstances, it appears that the public interest would be best served by appropriate measures being taken to ensure that well drilling and producing operations are completely safe and cause practical minimum environmental effects.

4 LOCATION OF THE WELL

4.1 Views of Dome

Dome proposed to drill a directional well from a surface location in Lsd 14-3-36-7 W5M (14-3). This surface site is situated on the south escarpment approximately 400 m from the River. The well would bottom in the prospective producing zone at a point beneath the southwest quarter of section 10 and more or less directly beneath the River valley (Figure 2). Dome submitted that it had originally considered two sites in the River plain a short distance north of the River's edge but was precluded from utilizing these sites because of setback distance from existing residential and public facilities and environmental impact considerations on the River valley. Dome then considered directionally drilling the well from a site approximately 100 m south of the River. In discussing this site with local landowners it became aware of concerns about the potential noise, odours, adverse effects on campers, and possible environmental damage to the River valley. In order to reduce concerns, Dome then proposed to relocate the proposed drilling site 400 m south of the River and in an area suitably level for a drilling site. Dome stated that it would not be feasible to attempt directionally drilling the well from any point farther southward than it had chosen.

4.2 Views of the Interveners

Living Faith submitted that it was concerned that the surface location of the well was too close to its facilities. Should the well prove to be successful, portions of its lands could be effectively sterilized because of setback requirements. This could result in restricting its growth and therefore its survival as a religious and education centre. Living Faith suspected that a sour gas well in such proximity to its facilities could cause a negative reaction on persons otherwise intending to utilize the centre because people would have a concern regarding the risks posed by the well. This would also discourage parents from sending children to camp or for schooling at the centre, or from participating in other activities. Support for the Living Faith Centre could thereby be eroded down to a level where financial survival would no longer be possible.

Mr. Zigler stated that he believed the location was too close to the River, the Living Faith Centre, and other residential areas. He argued that if a producing well was drilled as proposed, portions of his property could be restricted for future development. He therefore suggested that the farther south the surface location was moved, the better.

Mr. Smart submitted that because of the location of the well in the the River valley the risks of environmental damage existed. Should fluids escape from the lease in the event a mishap occurred, these could enter the River system and be carried downstream, affecting a large area.

The Chamber of Commerce recognized that because of the nature of the well and proposed surface location, some area residents might have problems in planning future development. It stated that such impacts must be borne in order to allow petroleum activities to continue. Further, it pointed out that existence of other wells and production facilities in the area attest to the fact that such facilities can be reasonably compatible with other land uses.

4.3 Views of the Board

The Board notes that several of the concerns raised by local interveners pertain to potential impacts on current or future development of their lands. Those matters are addressed in Section 7.

Respecting suitability of the surface location, the Board notes that the initial surface location some 100 m south of the River would have been considered adequate for protection of the River from potential damage from well site runoff or spills. Evidently Dome moved the site farther south to allay the concerns of nearby landowners respecting other potential real or perceived impacts of the well including safety, odours, and noise. Continued qualified opposition from nearby landowners illustrates that this additional step was not fully successful.

The Board's view is that Dome has taken all reasonable measures to relocate the surface site and that displacement farther from the bottom-hole target might prove counter-productive by increasing risks with drilling-hole problems and well completion and maintenance during production. The Board therefore believes that the well location chosen by Dome is at the optimum limit relative to the bottom-hole target and should not be moved farther away.

5 DRILLING OF THE WELL

5.1 Views of Dome

Dome anticipated it would require approximately 110 days to drill and complete the well. This would include a 2-week time period for penetration and completion of the potentially critical zone.

Dome stated that it had developed its drilling program to ensure the well would be drilled safely and efficiently. To this end, it had incorporated equipment and drilling procedures which met or exceeded ERCB regulations. Dome had surveyed data from other wells in the general vicinity to identify potential drilling problems and incorporate solutions to these problems in advance of its program. A highly competent supervisory staff would be on site at all times. In accordance with ERCB requirements, appropriate personnel would be certified in well control and blowout prevention drills and safety meetings would be conducted on a regular basis.

Dome submitted that it had prepared an Emergency Response Plan (ERP) which would ensure the safety of residents or others in the area if a release of sour gas were to occur during drilling of the well. The plan is based on the delineation of two zones. The first includes residents within 2 km of the well; the second extends to a 4-km radius. Three stages of alert were defined by Dome dependent on the degree of risk of a sour gas release. Given this step-by-step procedure for dealing with any problem, Dome submitted that it had developed a plan which would adequately deal with all the contingencies that might occur. Further, should the situation arise where evacuation did not occur as planned, or could not be accomplished without endangering the occupants of the area, the well would be ignited. Dome indicated in response to questions that it would ensure ignition of the well if an uncontrolled flow occurred which endangered area residents. Dome recognized that the finalized ERP must be approved by the Board before any well licence was granted and welcomed any constructive comments regarding improvements to it.

Regarding the specific points of concern set out by Living Faith, Dome would ensure that there is adequate transportation available while drilling in the critical zone. In addition, Dome would provide a siren system on the Living Faith site, as described in its ERP, and supplement its mobile monitoring unit with a stationary unit at the Living Faith Centre during drilling in the critical zone. Dome would also contact Living Faith when Dome was prepared to activate a "dry run" of an alert so that Living Faith could conduct a "dry run" of its own. In addition, Dome would be willing to assist in developing detailed procedures for the centre.

Dome also indicated that it was aware of unofficial campsites along the River valley that may be used by transient campers and would send out its staff to patrol and evacuate these areas in the event of an emergency.

5.2 Views of the Interveners

Living Faith submitted that it was not concerned with the technical merits of Dome's drilling program or the safety measures as set out in its ERP. It was concerned, however, as to how notification and evacuation of the up to 200 people attending activities at its centre and on its lands could be ensured in the event of a sour gas release.

Mr. Zigler stated that after listening to the evidence, he was concerned that Dome inappropriately considered the drilling of the well to be a routine matter. Mr. Zigler suggested that the ERP may be deficient and that more stationary H_2S monitoring should be utilized. In addition, the plan did not recognize camping sites in the area which were unofficial but highly utilized. Mr. Zigler suggested also that if a "dry run" was performed, it should occur near the time of drilling so that seasonal variations would not be a factor. As well, he requested that the Board staff be present on a continuous basis to scrutinize well operations and ensure full adherence to critical well safety requirements.

Mr. Smart submitted that one of his key concerns was whether or not, during the time of penetration of the critical zone, the ERP could adequately ensure the safety of his family.

The Chamber of Commerce submitted that it shared the safety concerns of area residents but was satisfied that Dome would do everything in its power to ensure that no accident occurred.

5.3 Views of the Board

Given the measures proposed by Dome, the Board is satisfied that the well could be drilled in a safe manner. As well, the drilling plan fully meets the current, very rigorous ERCB standards for safe design and drilling of critical sour gas wells. The Board notes that its field staff are charged with carefully scrutinizing and enforcing all critical sour well safe practice procedures. During drilling operations in the critical zone, an expected period of 2 weeks, Dome would be obliged to alert Board staff of all events and progress on a regular basis.

With respect to the ERP, the Board notes that this is a matter yet to be finalized. The continuing concerns identified by Living Faith, Mr. Zigler, and Mr. Smart would have to be addressed and the ERP formally approved by the Board prior to a licence being issued. The Board notes that Dome is receptive to constructive suggestions respecting the plan.

6 PRODUCTION OF THE WELL

6.1 Views of Dome

Dome stated that it was premature to discuss any well testing or production scenarios in detail until the well was found to be productive. Further, as stipulated by Part 7 of the Regulations, it noted that these matters were subject to future applications to the Board's Drilling and Production Department and were considered by Dome to be beyond the scope of the hearing.

For general information, however, Dome indicated that it anticipated it would require a 48-hour production test and corresponding flaring permit during the completion phase. Permanent production facilities would comprise a closed system with the wellhead being opened for a 1-day pressure measurement operation once a year and a major well workover every 5 years.

Dome had investigated a number of pipeline routes and was satisfied that a suitable pipeline route could be established to permit sour gas to be delivered to a sour gas plant if the well was found to be productive. However, it was premature at this time for Dome to specify which route would be applied for. If the well was productive, Dome would re-evaluate its ERP for Board approval and make any necessary changes. Regarding continuing concerns about the risks to public safety from a sour gas well, Dome pointed out that in Alberta there has not been a fatality among the general public that has been caused by a sour well.

6.2 Views of the Interveners

The interveners submitted that their main concerns centred around the impacts which could result from permanent production facilities located at the well site, these being primarily land use, environmental, and safety matters.

Living Faith wants to ensure at all times the safety of those who utilize the centre. This includes permanent staff and students located at the centre year round and visitors during special programs. The number of people on the grounds fluctuates throughout the year and access to trails is unrestricted. This raises concerns as to exactly how to monitor individuals and how to properly inform and educate them to react in a proper manner should a well site emergency occur.

Mr. Zigler submitted that it was his experience that oil and gas companies were unable to restrict the impacts of their operations to a lease area. He was concerned that flaring, noise, and odours could have adverse effects on the River valley and on persons in this area. He further requested that the Board undertake to have its staff present during all testing and workover operations to ensure that all procedures are carried out by the operator in a prudent manner.

Mr. Smart voiced a concern that any breakdown of production facilities could cause very real problems to both the environment and the health of area residents.

Mr. Dean, speaking on behalf of the Chamber of Commerce, acknowledged the environmental and health concerns of the area residents. However, he noted that as long as any company operating in the area conducted its work in a responsible manner and took all suitable precautions, there should be no danger to the public.

6.3 Views of the Board

If the well proves to be productive, a separate application setting out details of completion and surface facilities would have to meet Board requirements. Included would be measures to ensure safety for area residents and to protect the environment. Required facilities would include a continuous flare and back-up system to ensure that no H_2S is vented to the atmosphere. As well as remote control surface valves, the well would have to be equipped with a subsurface safety valve which would activate automatically or could be activated manually if surface facility controls are damaged or fail to operate.

During operations ERCB guidelines and regulations respecting flaring, noise, and odours would be enforced, and ERCB staff would be available to promptly investigate problems such as noise, odours, flaring, or spills. Additionally, considering the special sensitivity of a sour gas well in this particular area, if the well licence is granted and a productive well completed, the Board would expect the applicant to meet further specific conditions to address some of the concerns raised by the interveners, including

- the surface lease to be fenced to prevent trespass by recreational users or other unauthorized persons;
- a high-integrity surface site and road to be constructed which would preclude the escape of spills and allow ready access during all weather conditions;
- the site to be landscaped and maintained in an esthetically attractive manner incorporating suggestions of local residents; and
- the applicant to maintain an active community relations program with area residents, and ensure availability of local operations staff to deal promptly with any concerns respecting the well that are brought to their attention.

7 IMPACTS OF THE WELL ON PERSONS AND OFFSET LANDS

7.1 Views of Dome

Dome submitted that through the precautions encompassed in its drilling program and ERP, and as production would be through a closed system, effects on the surrounding environment should be innocuous and there would be negligible danger to area residents.

Dome said that it recognized the interveners' concerns over restrictions to future development of their lands and had attempted to relocate the well to reduce such impacts.

Respecting devaluation of lands, Dome submitted that this was a very difficult subject to address as many intangible factors could be involved. These could include fluctuating interest rates reflecting inflation or deflation from time to time, employment and demand for residences in an area, and personal perceptions, all affecting land prices. Dome believed that negative perceptions by persons in or utilizing an area were a problem of education, and Dome was willing to assist such groups as Living Faith to educate and inform persons in order to correct wrong impressions.

Dome stated that it felt development of oil and gas in Alberta is a fact of life and in many areas the benefits to the community more than offset the negative impacts that may affect a few people.

7.2 Views of the Interveners

Generally, the interveners stated that in addition to the adverse impacts they could perceive on health, safety, and the environment, the effect the well could have on land prices and their ability to develop such land as they saw fit were major concerns to them.

Living Faith submitted that it was concerned that future development of their lands, some 1.4 km northeast of the well site, may be restricted owing to sour gas setback restrictions. This could therefore preclude future expansion. Further, it was very concerned over the public's perception of an area where a sour gas well was near by. This could adversely affect the willingness of the public to use the Living Faith facilities. The effect would be to reduce Living Faith's source of income and, should the negative perception be strong enough, the actual survival of the organization could be endangered.

Mr. Zigler indicated that he shared Living Faith's concerns. He argued that he had future plans for developing camping, fishing, and canoeing facilities on his lands and was not in favour of the well since the necessary setback distances would preclude that development. He believed it could essentially sterilize portions of his property. Moreover, he had already invested time and money into recreational development on which, because of the well, he might not see a return. Mr. Zigler also suggested the well would have a negative effect on the value of the property and his ability to resell it should he wish to do so. Private individuals had already indicated to him that they would not be interested in purchasing property with a sour gas well near by.

Mr. Smart supported Mr. Zigler's comments and also stated that he believed the well would greatly devalue his property. Various landowners and real estate agents who agreed with him had fortified his suspicions that his property value would decrease should the well be drilled and prove productive.

The Chamber of Commerce contended that oil and gas development as a whole may actually increase land values in an area. The Chamber of Commerce felt that as activity increased in an area, so did the demand for land, especially acreages.

7.3 Views of the Board

The Board believes that, given the measures set out in Dome's drilling plan and ERP, the well could proceed safely with only minor impacts during the drilling and testing phase bearing in mind that critical zone activities would last only about 2 weeks.

Conversely, Living Faith, Mr. Zigler, and Mr. Smart were concerned about the impacts a producing sour gas well at the proposed site could have on development potential and future use of their lands. Even though parts of these lands are close enough to be within the Emergency Planning Zone, the Board would not see this as sufficient reason to deny granting the well licence. Nevertheless, recognizing that a producing well could typically be in operation for over 30 years, all reasonable measures should be employed to avoid frustrations and mitigate land use conflicts. In this particular case, the Board acknowledges that restrictions on development adjacent to the well could occur because of the sour gas setback restrictions that may be imposed by planning authorities. Such issues would be a question of compensation which is beyond the jurisdiction of the Board. In general, however, the Board would expect such impacts to be resolved by direct negotiation between the parties or through the courts if necessary.

8 DECISION

The Board is satisfied that the applicant has taken all reasonable and sound practical steps to ensure the safe directional drilling of a critical sour well with the surface site to be located in section 3-36-7 W5M and the bottom-hole target in section 10-36-7 W5M. With minor improvements to the ERP, it should be feasible to proceed.

Regarding further potential impacts on nearby landowners from a producing sour gas well, the Board is of the opinion that the licensee has clear obligation to prevent or at least minimize impacts from flaring, noise, odours, or other such effects. Additionally, adherence to ERCB regulations and guidelines should ensure minimal impacts for all but those in very close proximity (ie, 100 to 500 m) to the well.

While the Board recognizes that impacts on current land uses and future development could affect landowners, those are questions of compensation which are beyond the Board's jurisdiction.

The Board approves the application and upon receipt of a finalized and approved emergency response plan, the well licence will be issued subject to the provisions outlined in Section 6.3.

DATED at Calgary, Alberta, on 16 February 1988.

ENERGY RESOURCES CONSERVATION BOARD

N Strom

N. A. Strom, P.Eng.
Vice Chairman

F. J. Mink, P.Eng.
Board Member

J. P. Prince

J. P. Prince, Ph.D.
Board Member

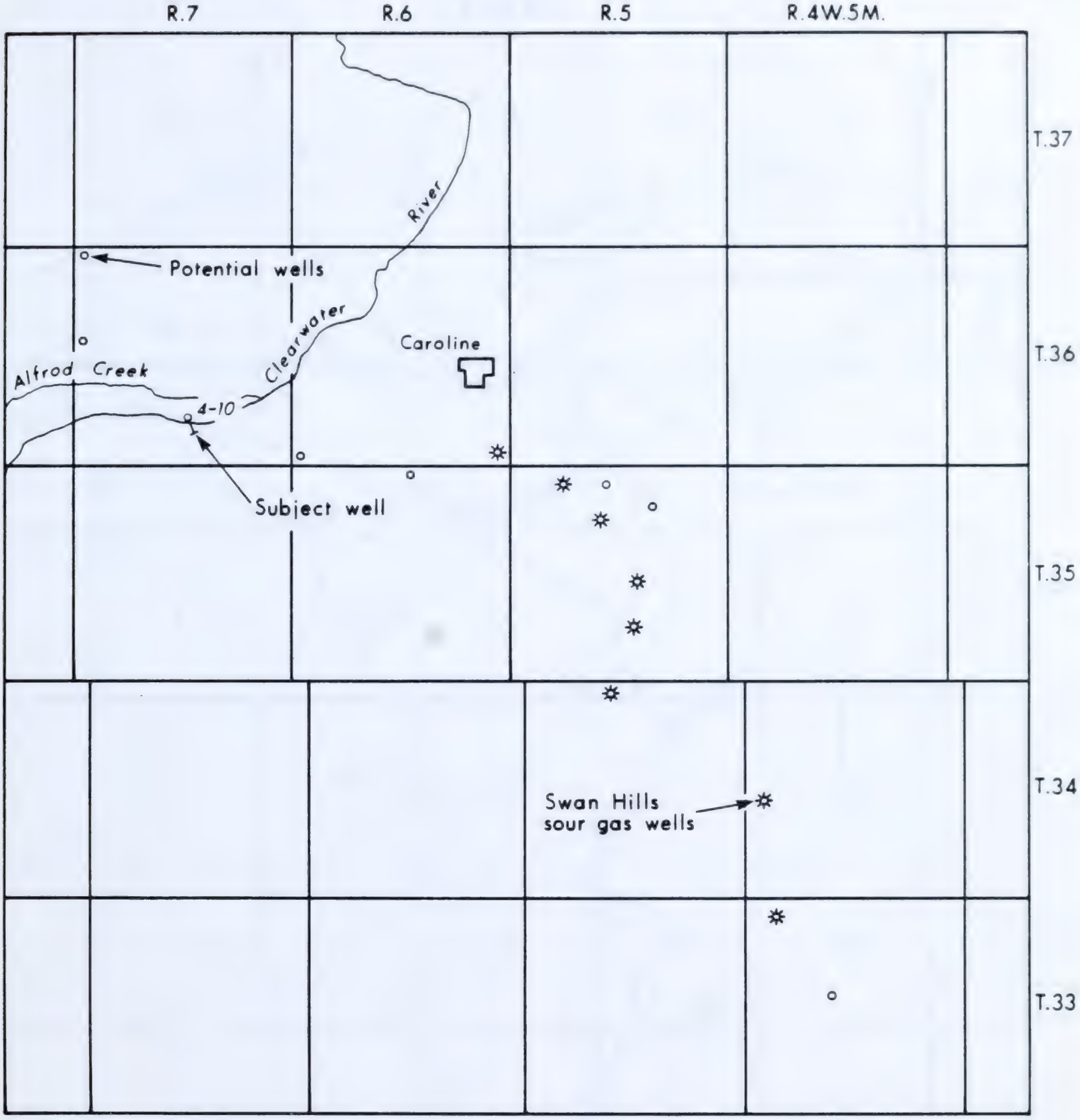

FIGURE 1 DOME ET AL CAROLINE 4-10-36-7W5
Application No. 871392
Dome Petroleum Limited

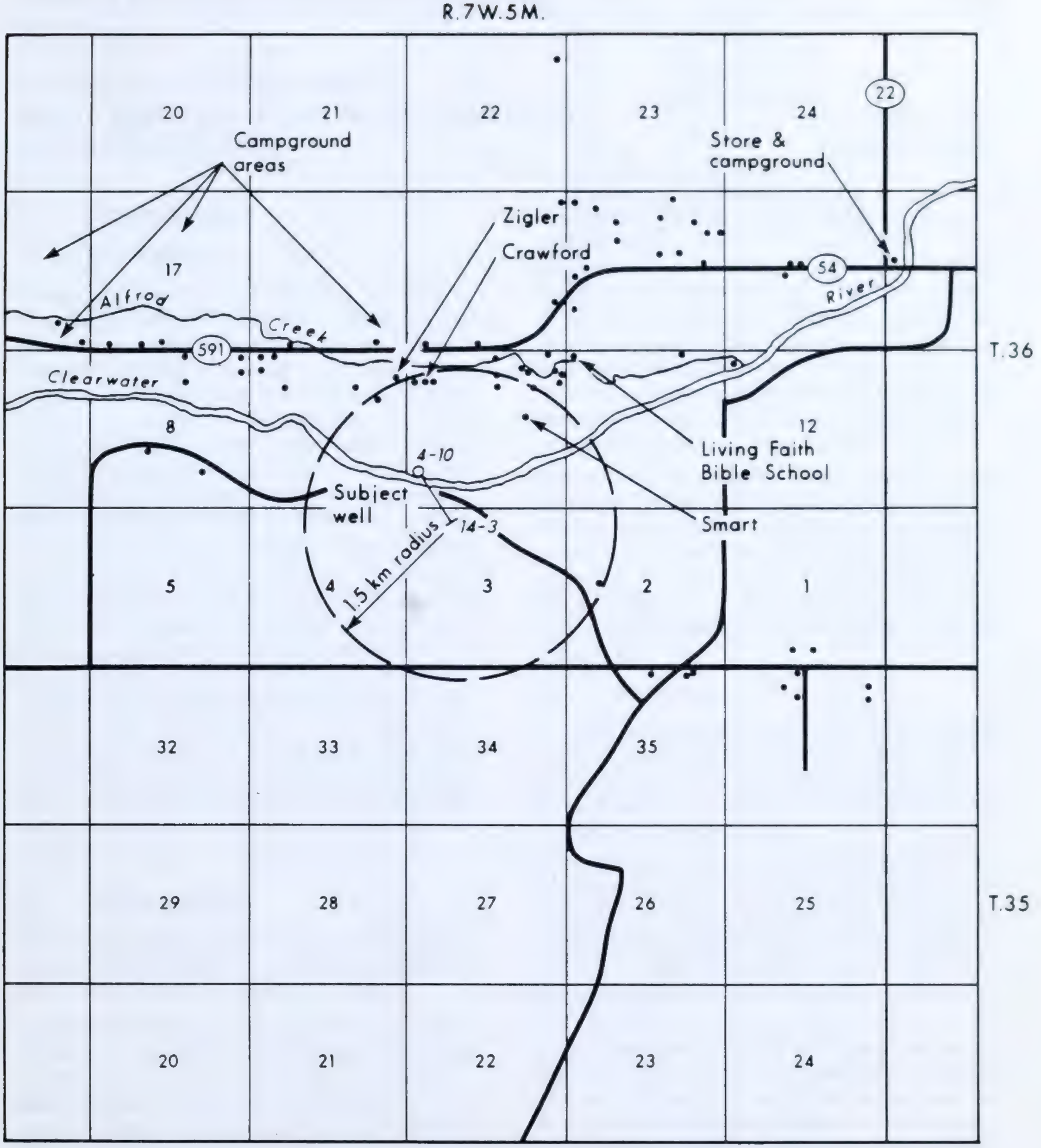

FIGURE 2 DOME ET AL CAROLINE 4-10-36-7W5
Application No. 871392
Dome Petroleum Limited

ENERGY RESOURCES CONSERVATION BOARD

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Calgary Alberta

SKIMMER OIL SEPARATORS LTD.
WASTE PROCESSING AND DISPOSAL FACILITY
LLOYDMINSTER FIELD

Decision D 87-21
Application 871196

1 INTRODUCTION

1.1 The Application

Skimmer Oil Separators Ltd. (Skimmer Oil) applied, pursuant to sections 7.001 and 7.002 of the Oil and Gas Conservation Regulations, for approval to construct and operate a waste processing and disposal facility located in legal subdivision 14 of section 31, township 51, range 2, west of the 4th meridian. The waste processing facility would receive and process approximately 270 cubic metres per day (m^3/d) of oily waste* trucked from various operators in the Lloydminster and surrounding fields. The products resulting from the process would be an emulsion of clean oil** and water, dead oil***, salt water, and sand. The emulsion of clean oil and water would be returned to the producer for further treating, dead oil would be delivered to the County of Vermilion River for road application and dust control or to other users having like applications for the material, salt water would be sent to an ERCB-approved water disposal well, and clean sand would be sold to Cardium Service and Supply Ltd. (Cardium) or provided to local contractors or farmers for spreading in low areas or under tanks to create a dry flat base. If volumes dictate, the sand may also be sent to a landfill area.

1.2 The Interventions

Interventions expressing concern and qualified opposition to Skimmer's application were submitted by Mr. and Mrs. H. Blair (the Blairs) and Mr. H. Corr.

The Blairs reside in the southeast quarter of section 6, township 51, range 2, west of the 4th meridian. They were not opposed to the concept of a waste processing plant in the general area but were very much concerned with the proposed construction in Lsd 14-31-51-2 W4M adjacent to their acreage.

Mr. Harvey Corr represented a group consisting of approximately 77 people (Mr. Corr and Group) residing within a 6-mile radius of the proposed site, and a list of signatures of those represented by Mr. Corr was filed at the hearing. Mr. Corr and Group submitted they were not opposed to the construction and operation of a waste processing plant in general but were concerned with the lack of technical data to support the application and the process, justification of location, details of sand disposal, need, and economics.

Interventions in support of the application were submitted by Mr. R. McIlwrick representing Temor Oil Services (1974) Ltd., Mr. W. King representing Lloydminster Heavy Crude Services Ltd., Mr. K. Ross representing Ro-Vac Pump Truck Services Ltd., Mr. S. Wilson from Musgrave Agencies, and Mr. G. Stevens representing Home Oil Company (Home Oil).

1.3 The Hearing

A public hearing of the subject application was held on 20 October 1987 in Lloydminster before Board members C. J. Goodman, P.Eng., Dr. J. P. Prince, and E. R. Brushett, P.Eng. Those who appeared at the hearing are shown in the table.

As a matter of convenience, final arguments by the applicant and intervener Mr. Corr and Group were forwarded in writing to the Board, with the applicant submitting a summary statement after the submission of both written final arguments. Mr. and Mrs. Blair and other participants chose not to submit a written final argument.

In final argument, Mr. Corr and Group challenged the status before the hearing of some interveners and referred to section 31 of the Act which deals with the status of the interventions as related to the possible reimbursement of costs. The Board is of the view that status as a local intervener for cost purposes is a matter separate from standing as an intervener in a proceeding before the Board. In this instance the Board is satisfied that those registered as interveners appeared properly before it.

2 ISSUES

The Board believes the main issues are

- the need for the waste processing plant,
- the use of and impact on groundwater,

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* "oily waste" means tank bottom sludge, ecology pit cleanings, or oil spill debris which may contain oil, sand, clay, dirt, produced water, heavy hydrocarbons, etc.

** "clean oil" is good quality and essentially pure crude oil.

*** "dead oil" is an oil that has a very low quality and little market value.

- the treatment process,
- the location,
- potential contamination of surface and groundwaters by spills and/or leaks (the melt-water channel),
- disposal of produced material, and
- odours, emissions, noise, truck traffic, and related issues.

2.1 The Need

Skimmer Oil described the types of wastes to be handled at this facility as tank bottoms, ecology pit cleanings, and spill debris. It submitted that by handling these wastes the need for ecology pits and tanks in truck company yards would be eliminated. Waste products could be delivered directly to the plant on a year-round basis.

In addition it was submitted that the waste products are currently being spread on county roads, causing poor road conditions and potential pollution problems.

None of the interveners questioned the need for this type of plant in this general area. Mr. A. Foulkes, representing the County of Vermilion River No. 24, along with local trucking company representatives Mr. McIlwrick, Mr. King, and Mr. Ross, supported the development for its benefit in general to the Lloydminster area.

Mr. Stevens, representing Home Oil, submitted that his company would benefit from the plant, as economics make it difficult for the company to justify the construction of its own full-scale waste processing facility.

The Board is satisfied that a method of handling waste oil in an environmentally safe manner is needed in this area. Should the application be approved, the Board believes that the installation of such a plant would be an improvement over current waste handling practices. However, the Board does not believe that the need for ecology pits would be eliminated and pits would remain as containment areas prior to further handling.

2.2 The Use and Impact on Groundwater

Skimmer Oil submitted that it has received a groundwater exploration permit from Alberta Environment to determine the feasibility of obtaining 30,000 Canadian gallons per day (gal/d) of water for industrial purposes. The permit has many conditions attached to it, three of which are:

- Skimmer Oil shall fully compensate all persons sustaining damage as a result of the examinations and surveys,
- A field survey of all wells within a 2-mile radius shall be conducted to ascertain location, ownership, water level, pump intake depth, and open intervals of these wells, and
- Two observation wells shall be drilled within 50 to 500 feet of the pumped well, one in the same aquifer as the pumped well and one in the next highest aquifer above the aquifer of the pumped well.

Skimmer Oil provided expert opinion by Mr. Clissold indicating that the Vermilion bedrock aquifer located in this area could supply the required 30,000 gal/d. Skimmer Oil submitted that, although unlikely, its water withdrawal could affect another water well in the area and therefore it would be willing to monitor some selected farm water wells during the required pumping test.

The Blairs stated that they have had problems with their 32-foot water well and believe their well would be affected by Skimmer Oil's water withdrawal. The Blairs stated they would be willing to have their well monitored while the pumping test was taking place.

Mr. Corr and Group presented local residents as witnesses who from lifetime experiences expressed concern with respect to withdrawal and contamination of domestic water supplies. The witnesses all had farm water wells which produced from different depths and some had previously experienced problems with their wells.

The Board recognizes the jurisdiction of Alberta Environment with respect to groundwater exploration and use and fully endorses the conditions set out in the permits. The Board believes that it, too, must be fully satisfied that groundwater tests will be performed properly and that the water withdrawal will not have an adverse effect on local residents. In this instance should the exploration for and testing of a water source be undertaken, the Board would require in addition to Alberta Environment's conditions that the closest three farm water wells be monitored for a period before, during, and after the pumping test.

2.3 The Treatment Process

Skimmer Oil stated that the proposed cleaning of oily wastes such as tank bottoms, oil spill debris, and ecology pit cleanings would result in disposal of an emulsion of clean oil and water, dead oil, clean sand, and salty water. The process would involve three working pits where the application of heat and fresh water over a period of time would start the cleaning process. The wastes would then be transferred to a hydrocyclone, shale shaker, and auger wash system where the cleaning would be completed. The applicant noted that there would be no chemicals added to the system in order to facilitate separation of oil, water, and sand.

Skimmer Oil stated that the facility would handle 270 m^3/d of sand using an average of 17,000 gal/d of fresh water. Water would be recycled within the plant process but this would not lessen the total fresh water requirement.

A small preliminary test of the process was performed in three 45-gallon drums of oily wastes over a 19-day period. Skimmer Oil provided samples of the contaminated and cleaned waste product along with an analysis performed by the Alberta Research Council which indicated the success of Skimmer Oil's small-scale test.

The Blairs stated that they did not think that the project would be viable, mainly because of an insufficient water supply in the area.

Mr. Corr and Group submitted that Skimmer Oil had not supplied sufficient technical information to demonstrate that the process is viable and environmentally safe. The Group questioned the applicability of the results from a 3-barrel 19-day test to a full-scale operation.

Mr. Corr and Group stated that the cleaning process would leave a residue which would contain many harmful contaminants. They also stated that the proposed process is experimental and the full impact of the water withdrawal for the process will not be known for a number of years.

The Board notes that the applicant plans to clean 270 m^3/d of wastes using 17,000 gal/d of fresh water in addition to water recycled. This indicates that Skimmer Oil would be adding 63 gallons of fresh water to clean each cubic metre, or 220 gallons, of sand, and that amounts to about 1 gallon of water to about 3.5 gallons of sand. The Board is concerned, based on the limited testing, that Skimmer Oil may not have tested its process at an appropriate scale to clearly confirm the amount of water required to process the expected volume of waste and therefore could find its operation constrained by its water use permit. Nevertheless, the Board believes that the process is similar enough to those processes currently used by industry to have the potential to be an environmentally safe alternative to current methods of oily waste disposal.

2.4 The Location

Skimmer Oil submitted that several sites were looked at; however, Lsd 14-31-51-2 W4M was chosen because the site was centrally located, had a good clay supply which could be used as a barrier to prevent fluid migration, was not suitable for farming, and the 1.25-mile access from the west did not pass any residences. The applicant submitted that it has an option to purchase 20 acres and has the necessary approvals to subdivide subject to obtaining all government approvals, including approval for the industrial use of a fresh water supply.

Skimmer Oil submitted that it has entered into a verbal agreement with the County of Vermilion River to redevelop the road shoulders along the 1.25-mile stretch from Highway 897 to standards set by the County.

The Blairs stated that the road to the west of the site was too narrow for truck traffic and has sharp shoulders, creating a dangerous situation for two vehicles attempting to pass. Also, the increased amount of truck traffic would endanger their children and cause increased noise and dust. They believed that the site would be too close to the melt-water channel and to their home. Mr. Corr and Group stated that the site is not centrally located and is too close to the melt-water channel where a significant supply of groundwater could be contaminated. The Group also stated that the land around the site is good farmland and that wildlife in the area would be adversely affected if the plant were to be constructed.

Mr. McIlwrick, Mr. King, and Mr. Ross, representing their own local trucking companies, submitted that the site chosen is centrally located relative to hauling of waste materials.

The Board accepts that a facility is needed in this general area and although the site may or may not be centrally located accepts the site to be sufficiently central to the area it is proposed to serve.

The Board notes that the road to the west of the site is public access and that Skimmer Oil has agreed with the County of Vermilion River to upgrade the road shoulders.

The Board accepts that possible contamination of the melt-water channel is a valid concern and, should the project be approved, adequate diking would be required and other precautions taken so that the melt-water channel would not be affected.

The Board notes that no evidence was presented to show that the wildlife in the area would be significantly affected by the installation of this facility.

2.5 Potential Contamination of Surface and Groundwaters

Skimmer Oil stated that the facility is to be built in a high area away from the melt-water channel and on a clay base. The processing facility would be built on a cement pad and housed in an insulated building. The cement used in construction of the pits associated with the process would be chloride and chemical resistant. The applicant submitted that the entire perimeter of the site would be diked and a groundwater monitoring system employed to detect any leaks. Skimmer Oil will also be joining the local Area R1 oil spill co-op.

The Blairs said that during high spring run-off there would be a chance of the dikes washing out and contaminants getting into the melt-water channel.

Mr. Corr and Group submitted that there would be a possibility of the dike washing out and, should any contaminants get into the melt-water channel, they could travel a long distance before being stopped.

Concerns were also raised with respect to spills migrating into groundwater aquifers and polluting water supplies. Mr. Corr and Group were also concerned with spills from the trucks travelling to and from the plant.

The Board understands that the plant would be constructed above the melt-water channel on high ground so that the dikes would not be adversely affected by spring run-off.

The Board believes that migration of spills into the groundwater would not occur, given the proposed method of construction. Nevertheless, the Board is of the view that concrete exposed to salt water needs to be inspected on a regular basis to ensure that leakage is not occurring. Also, a monitoring system must be in place for early detection of any leaks. The Board's Informational Letter IL 85-16 deals with the construction and monitoring requirements for cement pits.

2.6 Disposal of Produced Material

The treatment process would produce clean oil, dead oil, salty water, and clean sand. The applicant stated that its plant would not be treating the clean oil to break any emulsions and that the emulsions of clean oil and water would be transferred back to the producer for further treatment. Skimmer Oil said it has a verbal agreement with the County of Vermilion River to take the dead oil for use as a road dust suppressant. Salty water would be disposed of to either the MURPHY BLACKFOOT 3A-7-50-1W4 disposal well or the MURPHY MORGAN 2B-2-52-4W4 disposal well. Skimmer Oil stated that Cardium has agreed to purchase 50,000 tons of sand per year, provided the sand meets or exceeds the quality of test samples previously provided to Cardium. Cardium also has an option to purchase an additional 50,000 tons.

Skimmer Oil stated that, if the supply of sand was more than could be accepted by Cardium, it would dispose of the sand to local contractors for pipeline or tank shading*, to various parties for road sanding during the winter months, or to local farmers to fill low areas around corrals. Skimmer Oil also stated that it would landfill surplus sand, and would apply for a landfill immediately as a contingency.

Although the Blairs did not question the disposal of clean oil, dead oil, or salty water, they were concerned with the sand to be landfilled. They stated that, should the sand be disposed of in or near the melt-water channel, serious problems could occur.

Mr. Corr and Group expressed concern with the disposal of clean oil and dead oil because of the numerous contaminants they said were in these products. They also stated that they were concerned about salt water disposal because of the trucking to the water disposal wells and the possibility that the disposal wells had not been cemented or cased properly. They submitted that local farmers in the area do not want the sand on their land and that farmers are concerned about possible contamination to groundwaters.

If the application is approved, the Board would be satisfied with the clean oil and water going back to its source, the producer, but notes that should Skimmer Oil decide to install treating equipment to remove the water from the clean oil, a separate application would have to be submitted to the Board.

The Board notes that the dead oil would not be going back to the producer and that Skimmer Oil would dispose of dead oil by agreement with and delivery to a responsible party. Should this not be possible now or in the future, Skimmer Oil would be required to notify the Board's Wainwright Field Office of its plans prior to changing its disposal of dead oil.

The Board is satisfied with Skimmer Oil's plans for disposal of salty water.

Sand disposal to Cardium is acceptable; however, sand disposal to contractors or to the farming community would require site-specific approval. Sand disposal to a landfill area in or near the melt-water channel is not appropriate.

2.7 Odours, Emissions, Noise, Truck Traffic, and Related Issues

Skimmer Oil submitted that to lessen both noise and odours its process would be inside an insulated building. Noise associated with the process would be from two front-end loaders and from trucks travelling to and from the facility. To further prevent odour problems, Skimmer Oil stated it would not accept products containing H_2S. All trucks would be monitored with portable H_2S detectors and turned away if carrying H_2S product. Skimmer Oil would install a general H_2S alarm system to monitor for H_2S around the site even though it did not intend to allow any H_2S product on site.

Skimmer Oil submitted that there would be approximately 40 vehicles per day travelling to and from the facility and that these vehicles would use the road running west of the site. It plans to post signs on its roadway discouraging the use of engine retarder brakes, discouraging heavy vehicles from travelling east of the site, and encouraging a 70-kilometre-per-hour speed limit. Skimmer Oil further submitted that truckers are courteous and, if requested, will not travel east of the site.

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* Sand used for pipeline or tank shading makes a flat dry base.

The Blairs stated that they had moved to the country for its quiet and serene atmosphere, and that Mr. Blair, who worked in the oil industry, knew that this facility would create noise and odours disrupting their life style. The Blairs were concerned that trucks containing H_2S products would create odour and safety problems at their residence. Mrs. Blair stated that the installation of a general H_2S alarm would help alleviate some of their concerns over the H_2S problem.

The Blairs expected that truckers would travel to the east of the site even if signs were posted because the road to the east cuts off approximately 5 miles on the trip to Husky's Blackfoot Plant. They were also concerned that there would be conflicts between the school bus and the trucks.

Mr. Corr and Group submitted that the road west of the facility had not been constructed in a manner that would support heavy vehicle traffic. They also submitted that Highway 897 is in poor condition and would not withstand the increased truck traffic. The group was also concerned with noise from the front-end loaders and from the engine retarder brakes.

Mr. McIlwrick, Mr. King, and Mr. Ross stated that if signs were posted truck drivers would obey the signs. Mr. King stated that the road to the west of the site could be considered average as compared to other roads travelled in the area by truckers.

Considering that trucks containing H_2S would be turned away from the facility, the Board believes there would be no hazard from an H_2S release. The Board believes that odours in general should not be a problem; however, Skimmer Oil would be required to rectify any problem.

The Board agrees that there would be both short-term and long-term noise from the facility, short-term during the construction phase and long-term from general operations. The Board believes that Skimmer Oil could meet existing noise guidelines and notes that, should the guidelines not be met, Skimmer Oil would be required to take steps to reduce noise.

Truck traffic would be significantly increased, but the Board notes assurances given by trucking companies that they would act responsibly and follow directions of all posted signs. The Board concurs with the posting of signs and believes that Skimmer Oil should make instructions to truckers explicit. Should the truckers not obey such instructions, Skimmer Oil should refuse access or apply other pressure to ensure compliance.

3 DECISION

Having reviewed the evidence before it, including the concerns of the local people, the Board is prepared to approve Application 871196 for a waste processing and disposal facility in Lsd 14-31-51-2 W4M, subject to the following conditions:

- Skimmer Oil shall meet all current and future standards of noise and odour levels. Should either noise or odour levels exceed acceptable standards, Skimmer Oil must take immediate steps to resolve the problem.

- Skimmer Oil is to dispose of its dead oil to a responsible party. Should it vary the disposal of dead oil, it must give the Board's Wainwright Field Office prior notice.

- With approval of the owners, Skimmer Oil shall monitor three farm water wells in the immediate vicinity of the proposed site. The wells shall be monitored during the test and for a period of not less than 1 week before and 2 weeks after the test. Test results shall be included in Skimmer Oil's report to Alberta Environment, a copy of which shall be forwarded to the Board. Skimmer Oil is requested to approach Mr. and Mrs. Blair, Mr. G. Schantz, and Mr. M. Coleman for access to their respective water wells.

- Skimmer Oil shall further test the process to ensure the results stated in the application can be met. The Board is willing to accept the results of the proposed 270-m^3 test to be done prior to start-up; however, should the Board not be fully satisfied with the results of the 270-m^3 test, further testing will be required to ensure that the levels of hydrocarbon and salt that Skimmer Oil has stated can be obtained in the clean product, are obtained. Should Skimmer Oil itself decide instead that further testing prior to construction would be prudent, then those test results must be submitted to the Board. Skimmer Oil must advise Board staff prior to testing, as all tests will be monitored closely.

- Skimmer Oil may operate the plant for a period of not more than 12 hours per day starting no earlier than 6:00 am and ending no later than 8:00 pm. The Board would consider other hours if operating experience and agreement of nearby residents are positive.

- Skimmer Oil shall construct the cement pits with an underlying drainage system and shall install monitoring wells to allow for the monitoring of possible leaks.

- Skimmer Oil must clean out and inspect each cement pit a minimum of once per year to ensure pit integrity and no leakage into the ground. The ERCB area office in Wainwright is to be informed 2 working days before annual clean-out of the pits.

- As verbally agreed with the County of Vermilion River, Skimmer Oil must upgrade the shoulders of the road from the site west to Highway 897 to standards approved for the traffic proposed.

- Skimmer Oil must apply for and obtain approval of a landfill area which would not be within the meltwater channel even during high spring run-off.

- Should access to a salt water disposal well be lost, Skimmer Oil must suspend operations immediately and confirm with the ERCB field office before restarting operation.

- An H_2S alarm system must be installed for a trial period of 2 years. A report detailing the usefulness of this system must be submitted at the end of this time period and its operation is to be brought to the attention of ERCB field staff during site inspections.

DATED at Calgary, Alberta, on 17 December 1987.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

J. P. Prince

Dr. J. P. Prince
Board Member

E. R. Brushett

E. R. Brushett, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Skimmer Oil Separators Ltd. (Skimmer Oil) D. G. Milen	R. Clissold, P.Geol. A. Foulkes D. Willcock
Herb and Lorna Blair (the Blairs)	
Harvey Corr and the Marwayne Support Group (Mr. Corr and Group) J. W. Bodnar	B. Behnke L. Butler R. Cooke H. Corr L. Hines S. Inge A. Johnson R. Johnson T. Kent B. Luchyk R. Nohnychuk L. Taylor R. Young
Lloydminster Heavy Crude Services Ltd. W. King	
Sunrise Well Services Ltd. G. Graves	
Ro-Vac Pump Truck Services Ltd. K. Ross	
Temor Oil Services (1974) Ltd. R. McIlwrick	
Home Oil Co. Ltd. (Home Oil) G. Stevens	
W. H. Wilson	
Alberta Environment L. Fahner, P.Eng. A. Fernandez, P.Eng.	
Energy Resources Conservation Board staff R. Cox, P.Eng. R. Creasey, B.Sc. M. Sills	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

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HEARING DATE AND PROCEDURES
CANADIAN OCCIDENTAL PETROLEUM LTD.

Memorandum of Decision
Applications No. 860008
and 860009

PETROGAS PROCESSING LTD.
NORTHEAST CALGARY AREA

Applications No. 860004
860005, 860006 and 860007

1 INTRODUCTION

Canadian Occidental Petroleum Ltd. and Petrogas Processing Ltd. (Canadian Oxy for the purposes of this report) applied for a licence to drill a well and permits to construct sour gas and related pipelines in the Northeast Calgary area in April 1984.

The hearing of the applications was deferred until the completion of a number of technical studies.

In December 1985 Canadian Oxy submitted new applications to replace those originally filed. The new applications are for licences to drill two wells from Lsd 6-19-24-28 W4M, and for permits to construct sour gas and related pipelines to connect the new wells to the existing pipeline system connected to the Petrogas gas processing plant near Balzac.

Because a hazard assessment by Concord Scientific Corporation (Concord) was nearing completion, a pre-hearing meeting was held to consider the status of the Concord study, the need for and timing of a hearing, intervener funding, the possibility of identifying and/or scoping the issues to be addressed at the hearing, and other procedural matters.

The meeting was held 2 April 1987 in Calgary, Alberta, before a Board panel comprised of G. J. DeSorcy, P.Eng. (Chairman), N. A. Strom, P.Eng., and E. J. Morin, P.Eng, Acting Board Member. Those who appeared at the meeting are listed in Table 1.

Following completion of the meeting, the Board was informed that there might be a change in the schedule for the various Concord reports, from that outlined at the meeting. The Board requested a further review of the schedule for completion of the reports and holding of the public meetings and as a result, a revised schedule respecting the reports was proposed in a letter from Concord dated 27 April 1987. The letter was sent to participants in the pre-hearing meeting and any resulting comments are reflected in this Memorandum of Decision.

2 RELEVANT MATTERS

2.1 Status of the Concord Study

Concord stated that completion of the independent hazard assessment of the Canadian Oxy-proposed wells and associated facilities it had been commissioned to undertake in February 1986 had been delayed from its original target completion of June 1986. This occurred because the overall scope of the project was considerably expanded after the project started and because the review of its work by the Scientific Advisory Board (SAB) had been thorough. The project now includes three phases: Phase I, the development of a state-of-the-art hazard assessment model to calculate the extent and impact of a release of sour gas should one occur; Phase II, the development of a risk assessment model to address the risk of such an occurrence; and Phase III, the application of the Phase I and II models to the proposed wells and pipelines.

The 27 April 1987 letter from Concord advised that discussions had taken place between Concord and several of the pre-hearing meeting participants. The discussions related to the revised completion dates for the Concord reports, in particular the Phase II and III reports. Also discussed was the possibility for advance review of the reports by technical consultants for the public as was suggested by the East Calgary Sour Gas Investigation Committee (ECSGIC) at the pre-hearing meeting. In order to expedite the review process associated with the Concord study, and therefore allow the hearing of the Canadian Oxy applications to be convened as soon as possible, Concord and the SAB agreed to the selective review of the reports by technical consultants for the public prior to the reports being finalized and presented to the public. The proposed advance release dates to the technical consultants were 15 May 1987, 15 July 1987, and 31 August 1987 for the Phase I, II, and III reports, respectively. Public meetings have been scheduled for 25 June 1987 and 8 October 1987 to present the Phase I, and Phase II and III reports, respectively. The Phase I, and Phase II and III reports are to be finalized and released to the public around 15 June 1987 and the end of September 1987, respectively.

In response to the Canadian Oxy query respecting the role of Concord in relation to its applications, the Board notes that Concord was retained in accordance with section 16 of the Energy Resources Conservation Act to "...inquire into and report to the Board in respect of the matter in question...", that being the risk associated with the Canadian Oxy-proposed facilities. Further, the Board has arranged for Concord to formally release the results of its investigations at a hearing of the Canadian Oxy applications.

2.2 Need for and Timing of a Hearing

Canadian Oxy stated that it expected a hearing would be needed and that it should be scheduled now. It said that the realistic worst-case study recommended by the Sage study was a general assessment and not a critique of its applications, and commented that the hearing of its applications had already experienced considerable delay pending the completion of the expanded Concord study. It expressed concern that even further delay would result from not only the SAB review of Phase II matters but also the public review of the Phase II and III reports. Canadian Oxy believes any such further delay to be unreasonable and accordingly requested a hearing be scheduled for not later than mid September 1987.

At the pre-hearing meeting Concord recommended that the hearing of the Canadian Oxy applications not be held before 1 December 1987 to allow the needed public communication about its reports to occur. The schedule described in the 27 April 1987 letter would accommodate a hearing early in December 1987.

ECSGIC advised that once the Concord reports are available, it would be able to identify "experts" qualified to assist in its review of the applications. It said it was prepared, in its review of the applications, to resolve concerns of lesser importance through discussion with Canadian Oxy. This would result in only the more significant issues being addressed at the hearing. It recommended a registration of interveners once the Phase III report is finalized (early fall), followed by a pre-hearing meeting to identify and scope hearing issues and set dates for the filing of submissions and the hearing. Mr. Rooke stated that a January 1988 hearing date was likely.

Mr. Brown advised that once the Phase III report is finalized the City would need approximately 2 months to finalize its position respecting the applications. This tended to support the January 1988 hearing date suggested by the ECSGIC. Aldermen Clark and Havelock both said that concerned residents of Calgary should be given ample opportunity to review the results of the Concord study prior to the holding of a hearing. They emphasized the difficulty citizen groups encounter when undertaking such tasks over the summer months.

Bow North Surface Rights Association and the Summer Village of Chestermere (BNSRA) urged the Panel to select a hearing date that would allow for all interested parties to determine their positions after review of the final Concord reports. BNSRA preferred a hearing date sometime after October 1987.

The availability of the Concord study to the public is, in the Panel's view, very important to the consideration of the applications. Of equal importance is that an appropriate technical review of the "science" has occurred. However, it agrees with the applicants that the selection of a hearing date will encourage all participants to work toward expeditious completion and review of the Concord study. The Panel has carefully reviewed the schedule proposed in the 27 April 1987 letter and it believes that it addresses the objectives of convening a hearing as soon as reasonably possible and providing interveners with a "...reasonable opportunity..." to review both the Concord reports and the Canadian Oxy applications. This should facilitate determination of the major issues to be considered at a public hearing. Additionally, the schedule avoids the summer months for public meetings to present the Concord reports.

After considering the views of the participants the Panel has decided to schedule a hearing of the applications starting on 7 December 1987. Because of the concerns respecting timing associated with many of the key events, the Panel plans to pursue all reasonable actions available to ensure the scheduled dates for completion of the intervening steps are also met.

Table 2 sets out key steps leading up to the hearing. Key dates respecting the hearing include an initial Notice of Hearing, a Registration of Interested Parties (for mailing purposes), circulation of a relevant documents list, a final Notice of Hearing, Registration of Interveners, a pre-hearing meeting to identify and/or scope hearing issues and alternative hearing procedures, the closing date for final submissions, and lastly, the date of the hearing. Dates respecting the Concord study are also included.

2.3 Intervener Funding

Mr. Bruni of the ERCB staff advised that for proceedings for which sufficient "lead time" is available or for particularly complicated matters, the Board will entertain applications for advanced funding providing a reasonable budget is provided. However, the expenditure of advanced funding would be at the risk of the intervener, bearing in mind that amounts ultimately awarded are usually decided after the hearing of the proponents' applications.

Mr. Bruni noted that an advance of funds had been granted to the ECSGIC respecting Canadian Oxy's initial applications, and that the ERCB, the City, and Canadian Oxy had participated in the award.

Canadian Oxy indicated, with some reservations, a general willingness to co-operate to the extent possible in the area of advance funding.

BNSRA indicated it would submit a budget at the appropriate time.

The City supported the funding of groups of Calgary citizens but did not indicate whether or not the City would be able to provide assistance in this regard.

ECSGIC raised questions respecting costs associated with the negotiation process prior to the hearing and advised that it would only be able to prepare a budget for an advance after the Concord reports were available. ECSGIC noted that it is made clear to the experts it retains that they must be able to justify their costs to the Board or else "...they don't get paid".

The Panel recognizes that funds will be expended throughout the communication process associated with the Concord study, as well as the resultant negotiation and application review process. It is prepared to entertain requests from interested parties for advances related to the two general processes, providing budgets are submitted. It is the Panel's expectation that some discussion between the proponents and cost applicants will be required respecting communications and pre-hearing negotiation-related costs. Groups planning applications for costs are requested to discuss their specific circumstances with the Board's Legal Department.

2.4 Issues and Hearing Alternatives

With the exception of the applicants, participants generally were of the view that the identification or scoping of hearing issues and possible procedures would be premature without an opportunity to review the Phase III report. However, all participants were prepared to discuss alternatives to formalize hearing issues as well as ways to better arrange hearing procedures.

As noted in the attached Schedule of Key Steps, the Panel plans to hold another pre-hearing meeting in October 1987. It believes that the identification and/or scoping of hearing issues and alternative hearing procedures will be more easily accomplished at that time.

2.5 Relevant Documents

Several of the meeting participants stated that a list of relevant documents would not only assist preparation for the hearing, but also streamline it. The Board agrees with the participants and accordingly has requested the hearing staff to prepare a list of documents relevant to the applications to be made available to interested parties by 15 June 1987. Individuals would be requested to comment on the list, noting documents which should be included on the list or those that are no longer relevant.

3 SUMMARY AND CONCLUSIONS

The Panel has set the hearing of the Canadian Occidental Petroleum Ltd. and Petrogas Processing Ltd. applications for 7 December 1987. A Notice of Hearing will be issued in due course.

Because of the many delays that have already occurred in considering these applications and recognizing the extensive preparation time available to prospective participants, the Board does not foresee a circumstance which would lead to a further delay in the hearing.

DATED at Calgary, Alberta, on 19 May 1987.

GJDeSorcy

G. J. DeSorcy, P.Eng.
Chairman

N Strom

N. A. Strom, P.Eng.
Vice Chairman

Morin

E. J. Morin, P.Eng.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Principals and Representatives
(Abbreviations Used in Report)

Canadian Occidental Petroleum Ltd.
Petrogas Processing Ltd.
(Canadian Oxy)
- Mr. A. L. McLarty
- Mr. T. R. Fountain, P.Eng.
- Mr. D. W. Parsons

Bow North Surface Rights Association
and the Summer Village of Chestermere
(BNSRA)
- Mr. P. Edwards
- Ms. S. Pier

Calgary Regional Planning Commission
(CRPC)
- Ms. B. Koch

City of Calgary
(City)
- Mr. R. Clark, Alderman
- Mr. J. Havelock, Alderman
- Mr. T. Brown

Concord Scientific Corporation
(Concord)
- Mr. R. Portelli
- Dr. E. Alp, P.Eng.

Scientific Advisory Board to the Concord Study
(SAB)
- Dr. R. Purvis, P.Eng.

East Calgary Sour Gas Investigation Committee
(ECSGIC)
- Mr. J. D. Rooke

Alberta Environment
(AE)
- Ms. K. Lowe

Energy Resources Conservation Board staff
- Mr. M. J. Bruni
- Ms. N. C. Harris, P.Eng.
- Mr. H. W. Knox, P.Eng.

Canterra Energy Ltd. and Mobil Oil Canada, Ltd. registered as observers to the proceeding.

TABLE 2 SCHEDULE OF KEY STEPS - NORTHEAST CALGARY

	1987							
	May	June	July	Aug	Sept	Oct	Nov	Dec
Draft Phase I to Consultant	15							
Initial Notice of Hearing	27							
Registration of Interested Parties		10						
Documents List Distributed		15						
Final Phase I		15						
Concord Public Meeting (Phase I)		25						
Draft Phase II to Consultant			15					
Draft Phase III to Consultant				31				
Final Notice of Hearing					2			
Final Phase II and III					28			
Concord Public Meeting (Phase II and III)						8		
Registration of Interveners						14		
Pre-hearing Meeting						21		
Filing of Submissions							20	
Hearing								7

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SMALL POWER INQUIRY
PROCEEDING NO. 870621

Memorandum of Decision
Pre-hearing Conference
10 June 1987

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1 BACKGROUND

On 9 April 1987, the Lieutenant Governor in Council, by Order in Council 211/87, requested the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB) to inquire into electrical generation by small power generators and to report back to the Government with such recommendations as are necessary or advisable.

On 12 May 1987, the two Boards held a planning meeting to obtain comments and views of interested parties on a number of matters pertaining to the inquiry. On 21 May 1987, the Boards issued a Memorandum of Decision that summarizes their views and decisions respecting the matters discussed at the planning meeting and provides a schedule for the inquiry. The schedule established as a result of that meeting is appended to this memorandum.

Items 3 and 4 of the inquiry schedule deal with pre-submission information requests and a pre-hearing conference to discuss those requests and any other inquiry-related matters. The pre-hearing conference was held at the offices of the ERCB in Calgary on 10 June 1987 before ERCB Board Members C. J. Goodman, P.Eng. and F. J. Mink, P.Eng. and PUB Board Member J. R. Dunstan. Inquiry panel member, T. D. Hetherington, Q.C., of the PUB did not attend due to a prior commitment.

2 PRE-SUBMISSION INFORMATION REQUESTS

The Industrial Power Consumers Association of Alberta and the Small Power Producers Association of Alberta filed requests for information from Alberta Power Limited, the City of Edmonton, TransAlta Utilities Corporation, and the Electric Utility Planning Council (EUPC). The information requested can be summarized as falling into the following general areas:

- costs related to existing, presently-under-construction, and planned generation facilities,

- operating and maintenance information for existing, presently-under-construction, and planned generation facilities,

- fuel price information for thermal units,
- historic operating information for hydro units,
- input data for EUPC report "An Analysis of Small Power Production",
- historic system peak and energy load information,
- definitions and methods of calculating various avoided costs,
- 1987 EUPC load forecast(s),
- input data and other information relating to TransAlta's reports on monitoring of four small power production facilities,
- EUPC report on wind turbine study,
- information respecting the purchase of power from customers.

The utilities expressed concern about the relevance to the inquiry of some of the information sought. They also commented on the effort and time that would be required to comply with the requests, given the schedule that has been set out for the inquiry. The utilities indicated they would not wish to provide certain confidential information, such as incremental unit fuel costs. However, they would be prepared to respond to the information requests as required by the Boards.

The EUPC indicated it would be prepared to provide any information that is readily available. Certain of the reports requested are not yet completed but would be provided as soon as possible.

The Boards note the contention by IPCAA and the SPPAA that the requested information is relevant to the inquiry, and the stated intention of the SPPAA to illustrate how the present and planned system, exclusive of small power production, depends on a number of generating sources with varying costs and operating characteristics. The SPPAA intends to attempt to show how small power might fit into that system. Beyond this the participants were not specific as to how the information requested would be used.

All participants' submissions will form an important part of the inquiry and will assist the Boards as they respond to the terms of the Order in Council. The Boards would not wish to see the submissions, or the quality of those submissions, compromised by lack of information. However, the concerns expressed about time and effort necessary to comply with parts of the requests are also noted relative to the tight schedule of events leading up to the inquiry on 5 October 1987.

The schedule provides for information requests following the first submissions at the end of July. Although some time might be lost by not clearly defining current information requests now, it is recognized that it is still too early for participants to determine exactly what detailed information they need. In spite of any such lost time, the process should still be more efficient than requiring a lot of time and money to be spent covering every likely area of interest.

Therefore, the Boards will not compel the utilities and the EUPC to provide all of the specific information requested. However, the Boards expect the utilities to co-operate to the fullest extent possible in providing all information that is readily available, having regard for the schedule that has been set out for the inquiry but disregarding any views as to relevance. The Boards regard "readily available" information as that information which is already in hand, including information requiring some further short-term organization. The utilities are not required to provide information they normally consider to be confidential. However, if the information is available in a non-confidential form, it should be provided.

The Boards wish to again draw the attention of the participants to the Order in Council and to the direction provided therein, particularly with respect to the matter of principles and methods which should apply to the setting of a price or prices which could be paid for electricity produced by small power generators.

3 ADMINISTRATIVE MATTERS

A current "Participants Mailing List" will be maintained and provided to participants. The list will include active participants only, with one address per participant. Active participants are those who intend to file submissions to the inquiry and participate in the public hearing. Others, who might have an interest in the inquiry and wish to be kept informed, would be expected to make use of information placed for public viewing in the libraries and record centres of the respective Boards.

Confirmation was requested that every participant would receive copies of all material filed for the inquiry, and also information resulting from informal meetings and discussions between participants. As indicated in the 21 May 1987 Memorandum of Decision, all formally submitted submissions, requests for information, and responses will be made available to participants. However, the Boards do not believe it is practical, nor for that matter appropriate, to require that information from any informal meetings and discussions between participants be filed.

4 DEFINITION OF SMALL POWER PRODUCER

The Boards have considered the concern that the inquiry might not focus on the type of small power generation contemplated by the Order in Council. The Boards have also considered the suggestion that another step be introduced in the process to define the type of small power producer that would be addressed by the inquiry.

The extensive Participants Mailing List suggests there is a broad and diverse interest in the subject of small power and diverse views as to what is "small". It is unlikely, and certainly not expected, that all participants would address all possible aspects of small power production. It is more likely that each will address the subject according to its own interest. Nevertheless, the utility companies should bear in mind and allow for this broad and diverse interest during the preparation of their submissions.

Having regard for the Order in Council and the various views and comments expressed at the pre-hearing conference, the Boards have decided not to scope or restrict the inquiry to any particular group or type or size of small power producer.

DATED at Calgary, Alberta, on 19 June 1987.

ENERGY RESOURCES CONSERVATION BOARD	PUBLIC UTILITIES BOARD, ALBERTA
C. J. Goodman	
C. J. Goodman, P.Eng. Board Member	P. D. Hetherington, Q.C. Board Member

INQUIRY SCHEDULE

	MAJOR MILESTONES	DATE
1	Planning Meeting	12 May 1987
2	Finalization of Procedures	22 May 1987
3	Filing of Pre-submission Information Requests	3 June 1987
4	Pre-Hearing Conference (Memo of Decision 19 June 1987)	10 June 1987
5	Pre-submission Information Responses	24 June 1987
6	Filing of Submissions	31 July 1987
7	Information Requests	21 August 1987
8	Information Responses	11 September 1987
9	Commencement of Hearing	5 October 1987
10	Report to Government	End of 1987

ENERGY RESOURCES CONSERVATION BOARD — PUBLIC UTILITIES BOARD, ALBERTA
Calgary Alberta — Edmonton Alberta

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SMALL POWER INQUIRY
PROCEEDING NO. 870621

Memorandum of Decision
Planning Meeting
12 May 1987

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1 BACKGROUND

On 9 April 1987, the Lieutenant Governor in Council, by Order in Council 211/87, requested the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB) to inquire into electrical generation by small power generators and to report back to the Government with such recommendations as are necessary or advisable. The letter of transmittal requested that the two Boards submit a report by the end of 1987.

In order to plan for the inquiry, the two Boards held a meeting on 12 May 1987 to obtain the comments and views of interested parties on the following matters:

- the appropriateness of a public hearing or other possible methods of conducting the inquiry,
- in the event that a public hearing, or hearings, is deemed to be appropriate, whether or not the hearing(s) should be held jointly by the two Boards,
- the location and appropriate timing of any such hearing(s),
- the procedures to be used at any such hearing(s),
- the need for a pre-hearing conference,
- the issues to be dealt with in the inquiry, and
- any other matters that the participants at the meeting considered to be relevant to the inquiry.

The meeting was held at the offices of the Energy Resources Conservation Board in Calgary. It was co-chaired by the Chairman of the ERCB, Mr. G. J. DeSorcy, P.Eng., and the Chairman of the PUB, Mr. A. O. Ackroyd, Q.C. Those who participated at the meeting are listed in the attached table.

2 APPROPRIATENESS OF A PUBLIC HEARING OR OTHER METHODS OF CONDUCTING THE INQUIRY

A public hearing process or a process of written submission and reply, including an opportunity for written requests for information and responses, were identified as possible alternatives for conducting the inquiry. The participants indicated a strong preference for a joint hearing before both Boards.

The Boards have decided to hold a single public hearing, before both Boards, to consider submissions respecting the inquiry.

3 LOCATION AND APPROPRIATE TIMING OF HEARING

The majority of the participants expressed a preference that the hearing be held at one location. There was also a suggestion that, in co-operation with universities, a teleconferencing system could be set up so that residents of a particular community would have to travel only as far as the nearest university to participate in the proceedings.

There did not appear to be a consensus regarding where the hearing should be held. Having the hearing in a central location appeared preferable but there was also a suggestion that rural exposure should be provided. Several locations for the hearing were suggested.

There was general agreement that the hearing should be convened sometime in mid September to early October.

The Boards have decided to convene the hearing starting on 5 October 1987 at the offices of the ERCB in Calgary. They expect the majority of the participants, particularly those who will be dealing extensively with technical or economic information, to present their submissions, speak to them, and answer questions, in Calgary. However, the Boards recognize that there may be some individuals who wish to appear before the Boards to express their personal views, of a general nature, on the matter. The Boards would be prepared to consider sitting at one location in each of northern and southern Alberta to accommodate any such individuals. Such persons who do not wish to participate in the Calgary hearing should include a request to be heard elsewhere when they file their submissions. If held, these sittings would follow immediately on the main hearing in Calgary.

The Boards expect that a notice of hearing would be published shortly in appropriate daily and weekly newspapers throughout the province. In addition, it would be mailed to those who have expressed their intent to participate in the inquiry. A list of the participants is attached to this report. It will be updated and circulated as new names are added.

4 THE INQUIRY PROCESS AND HEARING PROCEDURES

There was general agreement that procedures and processes similar to the ones currently used by both Boards, with some possible modifications, would be suitable for the inquiry.

It was suggested that an additional step should be introduced in the process to allow for the interchange of information among participants prior to the filing of written submissions.

It was indicated that some persons who file submissions may not wish to appear at the hearing to speak to them. Provided information requests are complied with, it was suggested this should be allowed, although it might impact the weight given such submissions.

It was suggested that a pre-hearing conference to discuss the procedures to be used at the hearing or the entire inquiry process should not be necessary. However, some participants expressed the view that there might be some merit in a technical type pre-hearing conference. The chairman suggested that a pre-hearing conference might be used to address pre-submission information requests.

A suggestion was made that the utilities be the first to speak to their submission at the hearing, followed by the other participants. Others suggested that no special onus be placed on the utilities and that an alphabetic order of appearance would be appropriate.

The Boards have set out a scheduled inquiry process which it believes will be both efficient and achievable. The major milestones and dates are shown on Attachment 2. Procedures at the hearing itself will be similar to those now in use and will be outlined at the outset of the hearing.

The Boards have decided that because of the nature of the inquiry it would not be appropriate to single out any special or particular group to appear first. However, it does see some advantage in main participants proceeding first. It will therefore devise a schedule after it has had an opportunity to review the submissions. All interested parties will be notified of the intended sequence of appearances as soon as it is available.

The Boards urge all participants who file a written submission, particularly if it includes detailed evidence, to appear at the hearing. Those persons choosing not to appear at the hearing to speak to their submission are advised that this will be noted when the submission is considered.

The pre-submission information requests, milestone 3 in the process, should be filed on or before 3 June and directed to the ERCB, Calgary, attention of Fred Homeniuk, Hydro & Electric Dept., and should be copied to the party or parties that the participant believes might be in a position to supply the information. Some idea of why the information is being requested should be provided to facilitate discussion of the information requests at the pre-hearing conference. This conference is scheduled to be held on 10 June 1987 at the ERCB offices in Calgary.

5 ISSUES TO BE DEALT WITH IN THE INQUIRY

There was general agreement that the items listed in the Order in Council are an adequate basis for submissions and that it is premature to try to further delineate the issues already covered in the O.C. and the handout which was prepared by Board staff for the meeting.

It was suggested that the inquiry should also address sales of surplus electricity to parties other than utilities.

The Boards generally agree with the view expressed at the meeting that further delineation of issues is not practical at this time.

6 OTHER MATTERS

There was some discussion throughout the meeting about the role of staff of each Board in the inquiry. The Boards have decided that their respective staffs will not be involved in preparing and making a submission to the hearing. The primary staff roles will be in facilitating the process and advising and assisting the inquiry panel. In addition, staff will be available, where possible, as an information source to the participants throughout the process.

DATED at Calgary, Alberta, on 21 May 1987.

ENERGY RESOURCES CONSERVATION BOARD	PUBLIC UTILITIES BOARD, ALBERTA
	A.O. Ackroyd
G. J. DeSorcy, P.Eng. Chairman	A. O. Ackroyd, Q.C. Chairman

Attachment #1

PARTICIPANTS AT THE PLANNING MEETING

Organization	Representatives
City of Calgary Electric System	R. Goss
Bow Valley Research Ltd.	R. Ritter, P.Eng.
TransAlta Utilities Corporation	M. Patterson, Q.C.
Alberta Power Limited	C. Sheard
Industrial Power Consumers Association of Alberta	A. McLarty
Small Power Producers Association of Alberta	J. Foster, Q.C. D. Johnson S. Sears
City of Lethbridge	S. Bercov D. Hall
Champion Forest Products (Alta) Ltd.	T. Jensen
Canadian Petroleum Association	P. Sticksl
Canadian Hydro Developers Inc.	R. Keating, P.Eng.
Gulf Canada Ltd.	H. Martin, R.E.T.
City of Edmonton	M. McAvoy
Energy Conservation Branch, Alberta Energy	L. Sladen, P.Eng.
Nova, An Alberta Corporaton	P. Morales
Electric Utility Planning Council	D. Bacon, P.Eng.
Willow Creek Foundation	R. Stelfox H. Irwin
Nor'Wester Energy Systems Ltd.	J. Edworthy
Canadian Western Natural Gas	J. Willsher, P.Eng.
Alberta Wind Resource Development Corp.	J. Otis
SAIT Power Engineering Department	T. Grusendorf, C.E.T.
University of Alberta	C. Carter

PARTICIPANTS AT THE PLANNING MEETING (continued)

Organization	Representatives
Alberta Union of Rural Electrification Association	A. McGhan
CERI Energy Research Ltd.	G. Angevine
Arsene Farms	W. Arsene
Canadian Wind Energy	D. Starner
Energy Resources Conservation Board/ Public Utilities Board staff	T. F. Homeniuk, P.Eng. M. L. Asgar-Deen, P.Eng. R. Bruggeman, P.Eng. F. Shinyei, P.Eng.

The Coal Association of Alberta submitted written comments but was not present at the meeting.

Cleveland Engineering Services Ltd., South Beaver Lodge R.E.A., Lavern Doran, Cinabar Enterprises Ltd., and Dresser Products Ltd. indicated that they would attend the meeting but were not present.

Attachment #2

INQUIRY SCHEDULE

Major Milestones	Date
1. Planning Meeting	May 12, 1987
2. Finalization of Procedures	May 22, 1987
3. Filing of Pre-submission Information Requests	June 3, 1987
4. Pre-Hearing Conference	June 10, 1987
5. Pre-submission Information Responses	June 24, 1987
6. Filing of Submissions	July 31, 1987
7. Information Requests	August 21, 1987
8. Information Responses	September 11, 1987
9. Commencement of Hearing	October 5, 1987
10. Report to Government	End of 1987

Attachment #3

SMALL POWER INQUIRY

PARTICIPANTS' MAILING LIST

City of Calgary Electric System
P.O. Box 2100
2808 Spiller Road S.E.
CALGARY, Alberta
T2P 2M1
Attention: R. Goss

Bow Valley Research Ltd.
1313 - 44 Avenue N.E.
CALGARY, Alberta
T2E 6L5
Attention: Dr. R. Ritter

TransAlta Utilities Corporation
Box 1900, T1-902
110 - 12th Avenue S.W.
CALGARY, Alberta
T2P 2M1
Attention: M. Patterson

Alberta Power Limited
10035 - 105th Street
EDMONTON, Alberta
T5J 2V6
Attention: C. Sheard

Industrial Power Consumers Association
of Alberta
Suite 200, 11821 - 123 Street
EDMONTON, Alberta
T5L 0G7
Attention: A. McLarty

Small Power Producers Association of Alberta
#66 Suntree Lane
OKOTOKS, Alberta
T0L 1T0
Attention: J. Foster

City of Lethbridge
c/o D. W. Minion Consultants Ltd.
320 - 140 - 4th Avenue S.W.
CALGARY, Alberta
T2P 3N3
Attention: D. Hall

Champion Forest Prod. (Alta.) Ltd.
Postal Bag 8000
HINTON, Alberta
T0E 1B0
Attention: T. Jensen, Power & Recovery Supt.

Canadian Petroleum Association
3800 - 150 - 6th Avenue S.W.
CALGARY, Alberta
T2P 3Y7
Attention: P. Sticksl

Canadian Hydro Developers Inc.
119 Oakmount Way S.W.
CALGARY, Alberta
T2V 4Z2
Attention: R. Keating

Gulf Canada Ltd.
P.O. Box 130, 401 - 9 Avenue S.W.
CALGARY, Alberta
T2P 2H7
Attention: H. Martin

City of Edmonton
Century Place
9803 - 102A Avenue
EDMONTON, Alberta
T5J 3A3
Attention: M. McAvoy

Alberta Energy
Energy Conservation Branch
3rd Floor, Highfield Place
10010 - 106th Street
EDMONTON, Alberta
T5J 3L8
Attention: L. Sladen

Nova, An Alberta Corporation
9888 Jasper Avenue
EDMONTON, Alberta
T5J 3L6
Attention: P. Morales

Electric Utility Planning Council
c/o TransAlta Utilities Corporation
110 - 12th Avenue S.W.
CALGARY, Alberta
T2P 2M1
Attention: D. Bacon

Willow Creek Foundation
Box 790
FORT MACLEOD, Alberta
TOL 0Z0
Attention: R. Stelfox, Secretary-Treasurer

Nor'Wester Energy Systems Ltd.
Box 7, Site 32, R.R.#12
CALGARY, Alberta
T3E 6W3
Attention: J. Edworthy

Canadian Western Natural Gas
909 - 11th Avenue S.W.
CALGARY, Alberta
T2R 1L8
Attention: J. Willsher

Alberta Wind Resource Development Corp.
Box 1470
BLAIRMORE, Alberta
TOK 0E0
Attention: J. Otis

SAIT Power Engineering Department
1301 - 16th Avenue N.W.
CALGARY, Alberta
T2M 0L4
Attention: T. Grusendorf

University of Alberta
420 General Services Building
EDMONTON, Alberta
T6G 2H1
Attention: C. Carter

Alberta Union of Rural Electrification
Association
R.R.#4
RED DEER, Alberta
T4N 5E4
Attention: A. C. McGhan, President

CERI Energy Research Ltd.
3512 - 33 Street N.W.
CALGARY, Alberta
T2L 2A6
Attention: C. Angevine

Arsene Farms
P.O. Box 676
COALHURST, Alberta
T0L 0V0
Attention: W. Arsene

Canadian Wind Energy
969 - 12 Street B. South
LETHBRIDGE, Alberta
T1J 2V1
Attention: D. Sterner

The Coal Association of Canada
Suite 301, 1000 Eighth Avenue S.W.
CALGARY, Alberta
T2P 3M7
Attention: R. T. Marshall, President

Cleveland Engineering Services
P.O. Box 8545, Station "F"
CALGARY, Alberta
T2J 2V6
Attention: A. Cleveland, President

South Beaver Lodge REA
R.R.#1
WEMBLEY, Alberta
TOH 3SO
Attention: B. Smashnuk, President

Lavern Doran
Box 424
RED DEER, Alberta
T4N 5E9

Cinabar Enterprises Ltd.
1900 - 520 - 5th Avenue S.W.
CALGARY, Alberta
T2P 3R6
Attention: L. Nugent

Dresser Industrial Products Ltd.(Calgary)
Suite 418 Lancaster Building
304 - 6th Avenue S.W.
CALGARY, Alberta
T2P 1C2
Attention: D. Sundberg

Energy Resources Conservation Board
640 - 5th Avenue S.W.
CALGARY, Alberta
T2P 3G4
Attention: T. F. Homeniuk
Hydro & Electric Department

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